

Dear Desert Rock Air Permit Team,

It has come to my attention that there was a feasibility study for Concentrating Solar Power in New Mexico. The study is attached and the make-up of the task force is below. Please review the study, consult the task force members and then do an honest accounting of economics over the life time of the proposed Desert Rock Plant. This is likely to show that investments in CSP are competitive with investments in coal and certainly CSP is many orders of magnitude cleaner. This should be part of your BACT analysis for the proposed Sithe Global plant. Thanks. Leslie

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21 June 2004

From: Leslie Glustrom [mailto:lglustrom@gmail.com]
Sent: Monday, October 09, 2006 6:04 AM
To: desertrockairpermit@epa.gov
Subject: Be Sure to Consider Concentrating Solar Power

Hi Robert—When reviewing the air permit for the proposed Desert Rock plant please be sure to consider Concentrating Solar Power. Clearly avoiding air pollution is a critical part of finding the Best Available Control Technology for controlling air pollution!

We can make steam with “sunlight and mirrors” instead of by burning coal. The technologies exist and they are either cost competitive or close to it and will only become more so as we consider the increasing costs of coal and its transportation into the next century. We can be confident that sunshine will be delivered directly to the site for a few more billion years—with no carbon taxes or pollution control costs to be addressed.

I've attached the following reports for you to use in the review:

1) Western Governors Association report on solar that includes a long discussion of Concentrating Solar Power

2) Black and Veatch Report on CSP development and jobs for California—it is easily translated for New Mexico

3) A brief description of Concentrated Linear Fresnel Reflector technology that will soon be coming to this country from Australia.

A BACT analysis that doesn't include a review of CSP technologies will not have considered all "available methods, systems or techniques."

Thanks.

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NMCSPFeasibilityStudy.pdf

New Mexico Concentrating Solar Plant Feasibility Study

Draft Final Report

February 9, 2005

**Prepared for
New Mexico Energy, Minerals and Natural Resources
Department**



ENERGY • WATER • INFORMATION • GOVERNMENT

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Legal Notice

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Acknowledgements

Later.

Acronyms

APS	Arizona Public Service
B&V	Black & Veatch
BBER	Bureau of Business and Economic Research
BLM	Bureau of Land Management
CLFR	Compact Linear Fresnel Lens
COE	Cost of Electricity
CPV	Concentrating Photovoltaic
CSP	Concentrating Solar Power
CSPTF	CSP Task Force
CT	Combustion Turbine
DNI	Direct Normal Insolation
DOE	Department of Energy
EMNRD	Energy, Minerals and Natural Resources Department
EPC	Engineering, Procurement, and Construction
ESA	Endangered Species Act
GIS	Geographical Interface Screening
GRT	Gross Receipts Tax
HCE	Heat Conversion Element
HTF	Heat Transfer Fluid
HRSG	Heat Recovery Steam Generator
ISCCS	Integrated Solar Combined Cycle System
ITC	Investment Tax Credit
LD	Liquidated Damage
NADB	North American Development Bank
NMFA	New Mexico Finance Authority
NREL	National Renewable Energy Laboratory
NSTTF	National Solar Thermal Test Facility
O&M	Operation and Maintenance
PCU	Power Conversion Unit
PNM	Public Service Company of New Mexico
PPA	Power Purchase Agreement
PTC	Production Tax Credit
PV	Photovoltaics
R&D	Research and Development
REC	Renewable Energy Credit

RFP	Request for Proposal
RPS	Renewable Portfolio Standard
SBP	Schlaich Bergermann und Partner
SCE	Southern California Edison
SEGS	Solar Energy Generating Systems
SES	Stirling Engine Systems
SIC	State Investment Council
SIO	State Investment Officer
SNL	Sandia National Laboratories
SWEDFA	Statewide Economic Development and Finance Act
TEP	Tucson Electric Power
TMY2	Typical Meteorological Year Version 2
USFS	US Forest Service

Executive Summary

Early in 2004, Governor Richardson formed a Task Force to identify a viable commercial concentrating solar power project of 50 MW or larger that could be in operation by 2007. The CSP Task Force (CSPTF) was chaired by Cabinet Secretary Joanna Prukop, New Mexico Energy, Minerals and Natural Resources Department (EMNRD), with members from many state agencies, all of the state's investor owner utilities, and representatives from industry groups and the national laboratories. Craig O'Hare, Special Assistant for Renewable Energy, EMNRD, was the lead staff contact to the CSPTF.

ENMRD assembled a team led by Black & Veatch Corporation and supported by Platts Analytics, Kearney & Associates, and Morse Associates to perform a comprehensive CSP feasibility study to identify viable pathways for the development of a commercially operating CSP power plant in New Mexico by 2007. The Black & Veatch team assessed the commercial viability of the full range of CSP technologies, identified favorable siting opportunities with New Mexico, analyzed the impact of a range of incentives on the cost of electricity from a CSP plant, identified prospective markets for CSP power, and examined a variety of plant ownership options. Ultimately, the Black & Veatch team identified multiple pathways for the development of a commercially operational CSP plant in New Mexico by 2007.

Technology Options

The cost, performance and risk factors of all current CSP technologies – power tower, parabolic trough, dish-Stirling, and concentrating photovoltaics – were investigated. These technologies are shown on Figure ES-1. The specific factors considered in the evaluation included the following:

- Development status.
- Equipment reliability.
- Industry capability and depth.
- Risk assessment.
- Storage options.
- Performance.
- Equity requirements.
- O&M costs.
- Cost of energy.

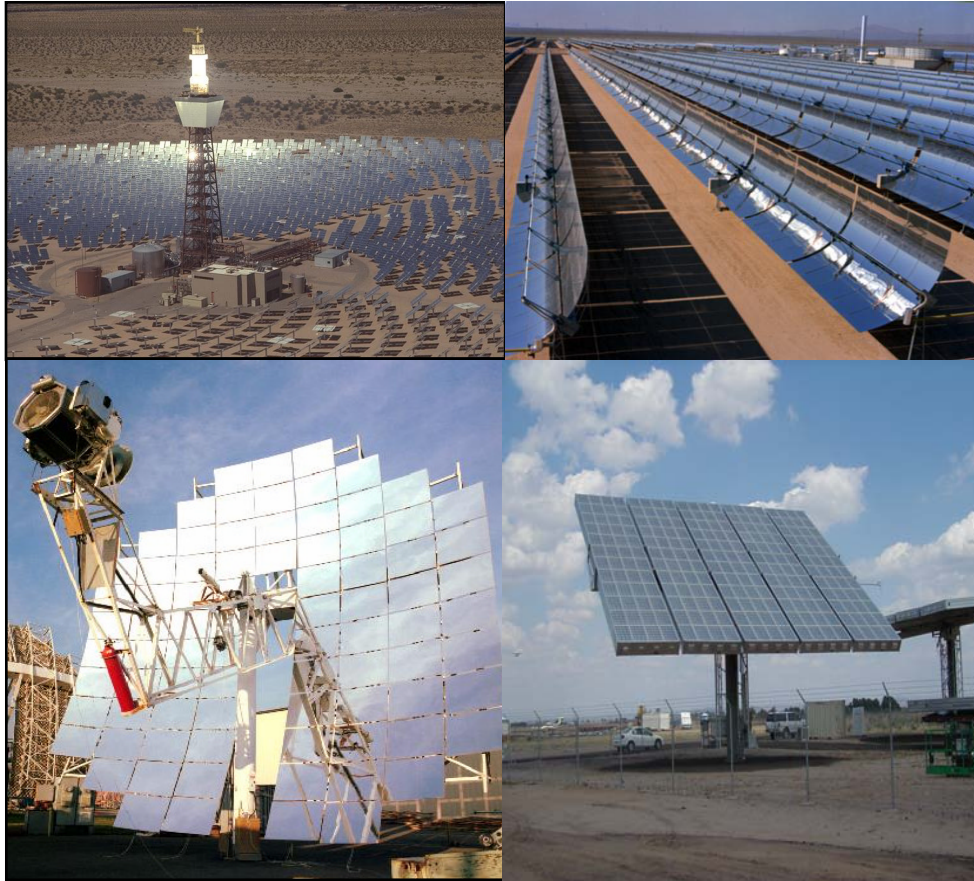


Figure ES-1
CSP Technologies

(Clockwise from upper left: Power Tower, Parabolic Trough, Dish-Stirling, and CPV)

- Water use/dry cooling.
- Siting effects.
- Transmission considerations.

Parabolic trough technology was deemed to be the only CSP technology ready for a commercial project by 2007. While both 50 MW and 100 MW trough plants were characterized, subsequent evaluations focused on five 50 MW trough system configurations. The reference plant had no thermal storage. To better match the output to the demand, two of these configurations had three and six hours of thermal energy storage, respectively. A fourth system used hybridization with natural gas, providing the ability to guarantee on-peak delivery. Dry cooling replaced wet cooling in the fifth trough system, greatly reducing annual water usage. Although power tower, dish-Stirling, and high concentration photovoltaic technologies have distinct capabilities and significant potential, they were deemed to be in the pre-commercial stage and therefore unable to meet the requirement of a 50 MW or larger commercially operating plant by

2007. The non-trough technologies are currently more suitable for demonstrations in the 10 to 15 MW size.

Site Options

Satellite data were used to create a solar energy intensity map of the state and geographical information system (GIS) was used to identify level areas of currently undeveloped land throughout the state where the solar energy ranged from outstanding to excellent. Proximity to transmission, access to natural gas and water, and other site parameters were then used to identify two prime areas for CSP plants in New Mexico. These areas are shown on Figure ES-2. Location 1 is in the central portion of the state, in the vicinity of Albuquerque. Two sites were identified in this area, one 10 miles southeast of Belen and the other 2 miles west of Belen. Location 2 is in the southwestern portion of the state where three sites were identified. One site is immediately northwest of Deming; a second site is immediately northeast of Lordsburg; a third site is 12 miles southeast of Lordsburg. Because the solar energy intensity is somewhat higher in the southwest location, the cost of electricity from a CSP plant of any configuration will be about 1 cent/kWh lower there than for a similar plant located in the central location.

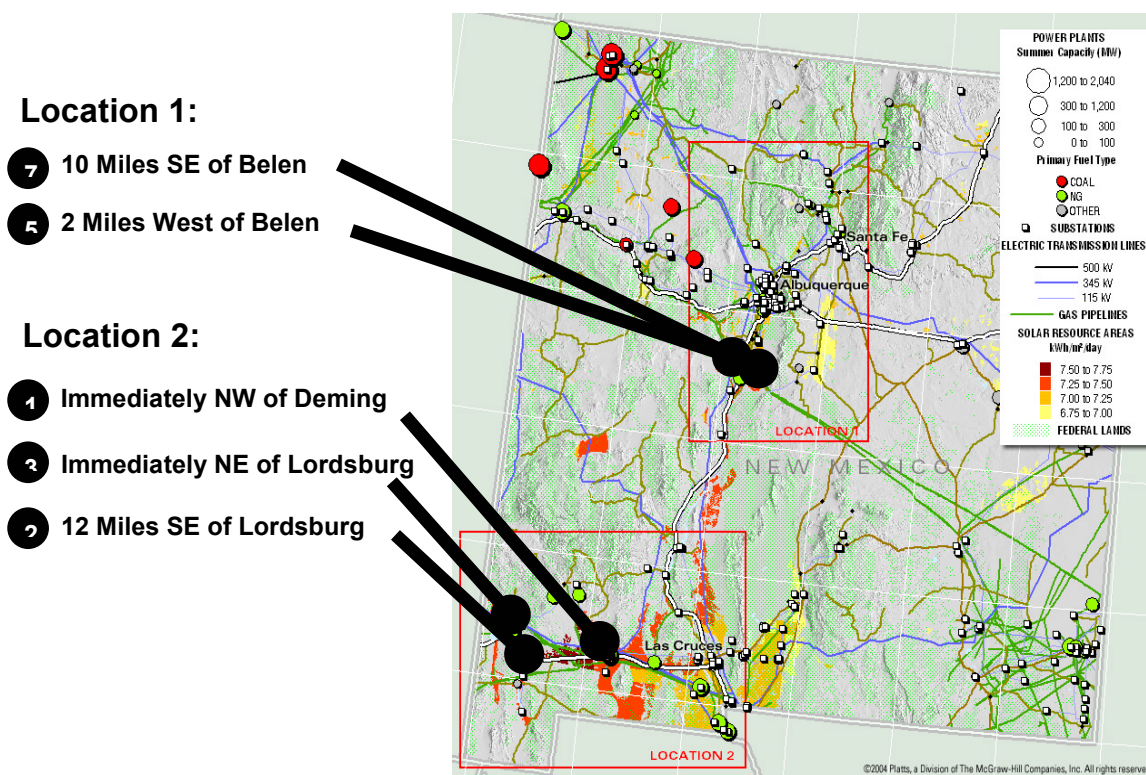


Figure ES-2
Selected Sites

Incentives

The most direct way to support a CSP plant is with a power purchase agreement (PPA) that provides sufficient revenue to cover all costs, services the debt, and provides an acceptable rate of return to project sponsors. Because of the high up-front capital costs of CSP projects, incentives and programs that increase the term of the debt and/or reduce the interest rate can reduce CSP project costs significantly.

The effectiveness of any particular incentive in improving the cost competitiveness of a CSP plant depends upon a variety of project-specific technical and financial factors including plant energy production level, debt terms, the amount of leverage, and the tax rate and liability of equity participants. For example, under current policies, we estimate that the cost of electricity for a privately-owned 50 MW parabolic trough plant financed with commercial bank debt and located in southwestern New Mexico is \$179/MWh. Our calculations indicate that a property tax exemption would reduce this cost by \$10/MWh, a gross receipts tax (GRT) exemption would reduce the cost by \$12/MWh, a state-sponsored partial performance guarantee would reduce the cost by \$22/MWh, a 2 cent/kWh state production tax credit (PTC), would reduce the cost by \$25/MWh, and all of these incentives combined would drop the cost by \$56/MWh.

Market Access

Discussions between the Black & Veatch team and transmission asset owning entities in New Mexico indicate that a 50 MW CSP plant located in one of the sites in central New Mexico would be able to serve the Albuquerque load center without the need for additional transmission investments. Furthermore, available information indicates that a 50 MW CSP plant in this location could transmit power to northwest New Mexico to the Four Corners region. However, access to markets beyond the Four Corners may be problematic because of the presence of transmission bottlenecks through the U.S. Southwest. Transmission bottlenecks are abundant heading west into Arizona, California and Nevada. Furthermore, west-to-east transmission constraints may limit power flows into Colorado's Front Range. The transmission situation appears to be even more challenging in southwest New Mexico. A transmission study must be conducted to determine if a 50 MW CSP plant located in one of the sites identified in southwest New Mexico could successfully transmit power to the combined Las Cruces/El Paso load center. Further, additional study is needed to determine if a 50 MW CSP plant could transmit power to Albuquerque. It appears, however, that short-term transmission capacity is available to transmit power into Arizona. Ultimately, the Black & Veatch team determined that the most likely scenario would be for the CSP plant to transmit power to the nearest in-state customer.

Ownership Models

Two CSP project ownership options were modeled by the Black & Veatch team: a utility ownership case in which a private entity develops the power plant and then sells it to a utility, which subsequently owns and operates the facility, and a private ownership case, in which the plant is developed and operated by a private entity that finances project construction with a combination of equity and debt from a commercial bank, development bank, or taxable bond issuance.

Development Pathways

The Black & Veatch team examined the entire landscape of technology, siting, market, incentive, and ownership options to identify the most promising pathways for the development of a commercially operating CSP plant by 2007. Ultimately, the following four most-favorable commercial development pathways were identified:

- Utility-owned 50 MW parabolic trough plant in southwest New Mexico.
- Privately-owned 50 MW parabolic trough plant in southwest New Mexico.
- Utility-owned 50 MW parabolic trough plant in central New Mexico.
- Privately-owned 50 MW parabolic trough plant in central New Mexico.

If any of these development pathways are pursued, the Black & Veatch team estimates that, with a full set of incentive options that includes a 2 cent/kWh state production tax credit, a property tax exemption, a GRT exemption, and a state-sponsored partial performance guarantee, the cost of electricity for a 2007 plant would range from \$89 to \$117/MWh, as shown on Figure ES-3. Although this is a very attractive cost for solar power, it is nearly double the current wholesale price of electricity. As a result, the Black & Veatch team notes that even in the presence of attractive incentives for CSP development, New Mexico load serving entities would be obligated to purchase CSP output at an above-market rate to induce the commercial development of a CSP plant in New Mexico by 2007.

In addition to these four commercial development pathways, the Black & Veatch team discussed the benefits of a state-sponsored CSP demonstration program involving one or more of the non-trough pre-commercial CSP technologies. In lieu of commercial financing, joint federal-state public funding, or private funding from a consortium of utilities would be required to embark upon a CSP demonstration project that would seek to advance the state of technical knowledge and operating experience for non-commercial CSP technologies.

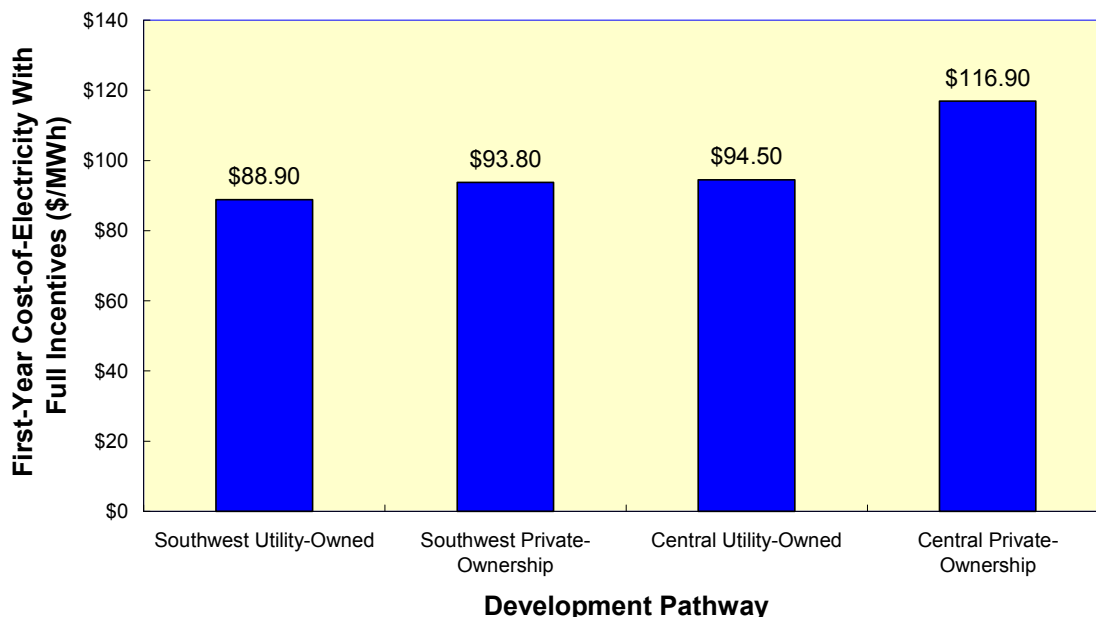


Figure ES-3
CSP Development Pathways

Benefits to New Mexico

The Bureau of Business and Economic Research (BBER) of the University of New Mexico performed a companion study, funded by the EMNR Department, of the economic impact on the state of building a single 50 MW CSP plant, a single 100 MW CSP plant, or five 100 MW CSP plants over a 10 year period. Their results showed that if a 50 MW CSP plant were to be built in New Mexico, the state's tax revenue, after any additional state expenses are subtracted, would increase by a total of \$104 million over the 30 year life of the plant. In addition, the state's economy would gain almost \$500 million over that same period and about 1,000 temporary construction jobs and 74 permanent plant operation jobs would be created. If the state were to provide the full set of state incentives, the cost to the state's treasury would be about \$33 million, leaving a net \$70 million.

The benefits to New Mexico from either a dish-Stirling or power tower demonstration are technology leadership and positioning the state to attract relevant manufacturing facilities to the state.

1.0 Introduction

New Mexico ranks second in the nation in solar resource potential. This largely untapped resource could provide more than 2,000,000 GWh per year of electricity. Although the resource is significant, barriers to the successful large-scale implementation of solar power are also significant. Solar system costs remain high, requiring wide-scale deployment to bring down costs. Transmission investments are needed to take full advantage of the state's solar energy resources by moving solar power to out-of-state electricity markets.

Early in 2004, New Mexico Governor Richardson formed a task force to identify a viable commercial concentrating solar power (CSP) project of 50 MW or larger that could be in operation by 2007. The CSP Task Force (CSPTF) was chaired by Cabinet Secretary Joanna Prukop, with members from many state agencies, all of the state's investor owner utilities, plus representatives from national laboratories and advocacy groups. Craig O'Hare, Special Assistant for Renewable Energy, New Mexico Energy, Minerals and Natural Resources Department (EMNRD) was the lead staff contact to the CSPTF. The goals of the CSPTF were to accomplish the following:

- Increase the contribution of renewable energy sources, particularly solar power, in New Mexico's future energy supply mix.
- Enhance involvement of the private sector in developing innovative approaches to electric power production in New Mexico.
- Stimulate job creation and overall in-state economic development, including attracting CSP-related manufacturing enterprises to the state.
- Position the state as a national leader in the development of CSP projects in order to facilitate future CSP projects throughout the West.

In mid-2004, the CSPTF retained a consultant team led by Black & Veatch Corporation to perform a feasibility study to define and scope a specific viable project or projects using CSP technology in New Mexico.

1.1 Feasibility Study Objectives

The primary objective of the feasibility study was to identify a specific financially viable project or projects. The state of New Mexico is interested in pursuing a project of significant scale (approximately 50 MW or greater) to take advantage of economies of scale, position the project for future expansion, and begin the process of realizing projected CSP cost reductions through substantial deployment.

A secondary objective was to pursue innovative CSP technologies or applications of technologies that have the potential for commercial competitiveness.

The goal of this study has been to facilitate a project that would be in commercial operation in 2007.

1.2 Feasibility Study Team

The team selected by the CSPTF was led by Black & Veatch Corporation, with other key team members being Platts, Kearney & Associates, and Morse Associates. The Black & Veatch (B&V) team also obtained consulting services from Advance Capital Markets and Center for Resource Solutions.

1.3 Economic Impact Study

The CSPTF also chartered a companion study, “The Economic Impact of Concentrating Solar Power in New Mexico,” which was performed by the University of New Mexico Bureau of Business and Economic Research (BBER), and completed in December of 2004. The BBER study evaluated the economic and fiscal impact of building CSP plants in New Mexico. Section 7.0 of this report summarizes key findings of the BBER study.

1.4 Report Format

The remainder of this study is formatted according to the seven project tasks:

- Section 2.0, CSP Technical Assessment.
- Section 3.0, State Siting Assessment.
- Section 4.0, Federal and State Programs.
- Section 5.0, Market Assessment.
- Section 6.0, Financing Assessment.
- Section 7.0, The Economic Impact of CSP in New Mexico.
- Section 8.0, Project Development Models.

2.0 CSP Technology Assessment

The purpose of the CSP technology assessment was to characterize the CSP technologies with respect to commercial readiness, cost, performance, reliability, and technical risk. When conducting an assessment of CSP technologies, it is important to understand that parabolic trough plants, dish-engine units, power tower systems, and concentrating photovoltaic (CPV) systems differ in their respective levels of technological and commercial maturity. Further, the assessment must examine the implications of these differences for the development of a commercial-scale CSP plant. In general, the procedure has been to examine the historical record of operating experience, locate publicly available CSP technical information, gather additional information from probable CSP system suppliers, and draw upon other relevant documentation.

2.1 Description of CSP Systems

2.1.1 Technology Overview

The four CSP options for large-scale power are shown on Figure 2-1.



Figure 2-1
CSP Technologies

(Clockwise from upper left: Power Tower, Parabolic Dish, CPV, and Parabolic Trough)

Concentrating solar thermal power plants produce electric power by converting the sun's energy into high temperature heat using various mirror configurations. The heat is then channeled through a conventional generator. These plants consist of two major subsystems: one that collects solar energy and converts it to heat, and another that converts heat energy to electricity. CPV plants provide power by focusing solar radiation onto a photovoltaic (PV) module, which converts the radiation directly to electricity. Either mirrors or lenses can be used to concentrate the solar energy.

CSP systems can be sized for village power (10 to 25 kilowatts [kW]) or grid-connected applications (up to 100 megawatts [MW]). Dispatchability is a very important characteristic. That is, solar thermal systems can either use fossil fuel to supplement solar thermal energy, or can use thermal storage to store solar-generated thermal energy for use at a later time. For example, high temperature thermal energy stored during the off-peak periods can be utilized during peak hours in the evening to generate electricity. These attributes, along with very high solar-to-electric conversion efficiencies, make CSP an attractive renewable energy option in the Southwest and other sunbelt regions worldwide.

2.1.2 Solar Resource in New Mexico

The solar resource for generating power from CSP systems is plentiful. In fact, the southwestern United States potentially offers the best development opportunity for CSP technologies in the world. In particular, the solar resource in New Mexico ranks high in the southwest region. Due largely to air conditioning loads, there is a strong correlation between electric power demand and the solar resource. The amount of power generated by a CSP plant depends on the amount of direct sunlight; that is, these technologies use only direct-beam sunlight, rather than diffuse solar radiation. The solar resource for preferred areas of New Mexico is discussed in Section 3.0.

2.1.3 Parabolic Trough Systems

In a parabolic trough system, the sun's energy is concentrated by parabolic curved, trough-shaped reflectors onto a receiver pipe (also called "absorber pipe," or "heat collection element") placed at the focal line of the parabolic surface. This energy heats a high temperature heat transfer fluid (HTF), flowing through the pipe and passing on to steam generators. The steam drives a conventional steam-Rankine power cycle to generate electricity. Figure 2-2 shows a row of trough collectors. A collector field contains many troughs in parallel rows aligned on a north-south axis.

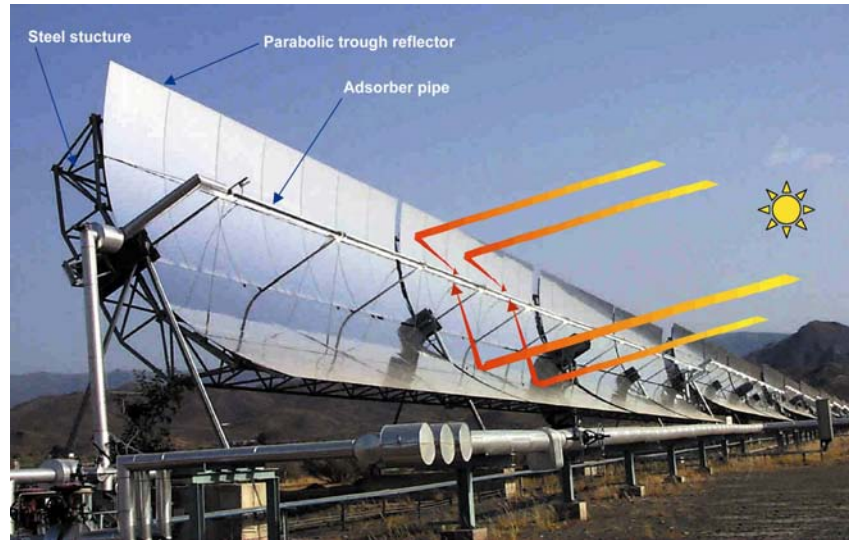


Figure 2-2
Photo of Parabolic Trough System

This configuration enables the single-axis troughs to track the sun from east to west during the day to ensure that the sun is continuously focused on the receiver.

Existing individual trough systems generate up to 80 MW of electricity. Larger systems are feasible and would have lower energy costs. While thermal storage could be utilized as previously described, all current parabolic trough plants are “hybrids;” they use fossil fuel to supplement the solar output during periods of low solar radiation.

A series of trough plants, with a cumulative capacity of 354 MW, were put into operation from 1985 through 1991. The Kramer Junction site with five 30 MW plants is shown on Figure 2-3.



Figure 2-3
Kramer Junction Trough Plant

These Solar Energy Generating Systems (SEGS) plants are operating satisfactorily, as demonstrated by the following:

- Operation and maintenance (O&M) costs have dropped sharply over time, coincident with performance gains.
- Component reliability has been good, but not excellent. Field experience has improved the lifetimes of mirrors and receivers. New models of receivers from current suppliers perform better, with evidence of significantly reduced failure rates.
- These plants, placed in operation from 1987 through 1989, set many performance records over the last 5 years.
- Using 25 percent energy input from natural gas via a supplemental boiler, capacity factors during Southern California Edison (SCE) on-peak operation have exceeded 100 percent for more than a decade (with >85 percent from solar operation).

Figure 2-4 illustrates the performance history of the plants at Kramer Junction. It shows that the electricity generation by solar energy alone has been consistently strong over the almost 20 years since the Kramer Junction plants began operation. The first few years show the plants coming on line. From 1991 to 1992, the worldwide effects of a volcanic eruption in the Philippines can be noted. Spare parts were limited in the early 1990's due to the demise of the supplier, but once that period passed, plant operation has been excellent. Advanced development of components and subsystems has also contributed to performance gains over the last decade.

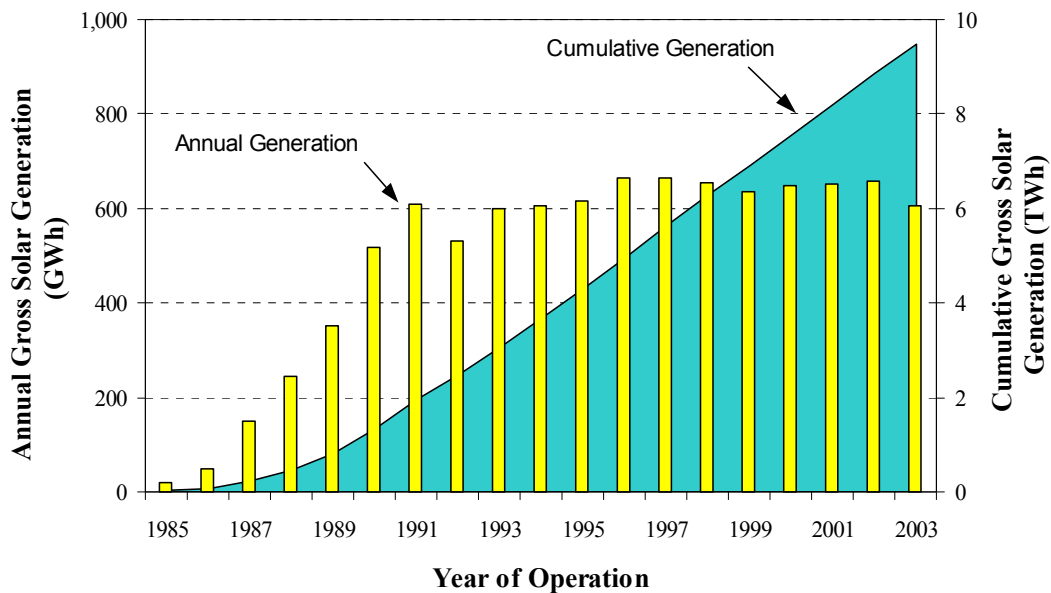


Figure 2-4
Kramer Junction Annual Performance

New commercial projects are either in the planning or active project development stage. At present, there are four active projects: 50 MW in Nevada, 1 MW in Arizona, and 2 x 50 MW, to be developed in two stages in Spain. The Spanish projects each include 5 hours of thermal storage. The planned future projects include the following:

- 2 x 50 MW, approximately 6 hours' storage, Solar Millennium, Spain.
- GEF Projects - Integrated Solar Combined Cycle System (ISCCS) - India; Egypt; Morocco; Mexico.
- Algeria - ISCCS.
- 500 MW, Israel.

2.1.4 Parabolic Dish-Engine Systems

A solar parabolic dish-engine system comprises a solar concentrator (or “parabolic dish”) and the power conversion unit (PCU). The dish, more specifically referred to as a concentrator, is the primary solar component of the system. It collects the solar energy coming directly from the sun (the solar energy that causes the casting of a shadow) and concentrates or focuses it on a small receiver. The resultant solar beam has all of the power of the sunlight hitting the dish, but is concentrated in a small area so that it can be more efficiently used. Glass mirrors reflect about 92 percent of the sunlight that hits them, are relatively inexpensive, can be cleaned, and can potentially last a long time in the outdoor environment, making them an excellent choice for the reflective surface of a solar concentrator. The dish structure must track the sun continuously to reflect the beam into the thermal receiver. The dish collects more solar energy than the trough system because it tracks in two axes, always pointing directly at the sun, in contrast to the trough system, which tracks in a single axis.

Figure 2-5 shows a parabolic dish-engine system using an efficient Stirling engine; this system is often termed a dish-Stirling system. The PCU includes the thermal receiver and the engine-generator. The thermal receiver is the interface between the dish and the engine-generator. It absorbs the concentrated beam of solar energy, converts it to heat, and transfers the heat to the engine-generator. A thermal receiver can be a bank of tubes with a cooling fluid, usually hydrogen or helium, which is the heat transfer medium and also the working fluid for an engine. Alternate thermal receivers are heat pipes wherein the boiling and condensing of an intermediate fluid is used to transfer the heat to the engine.

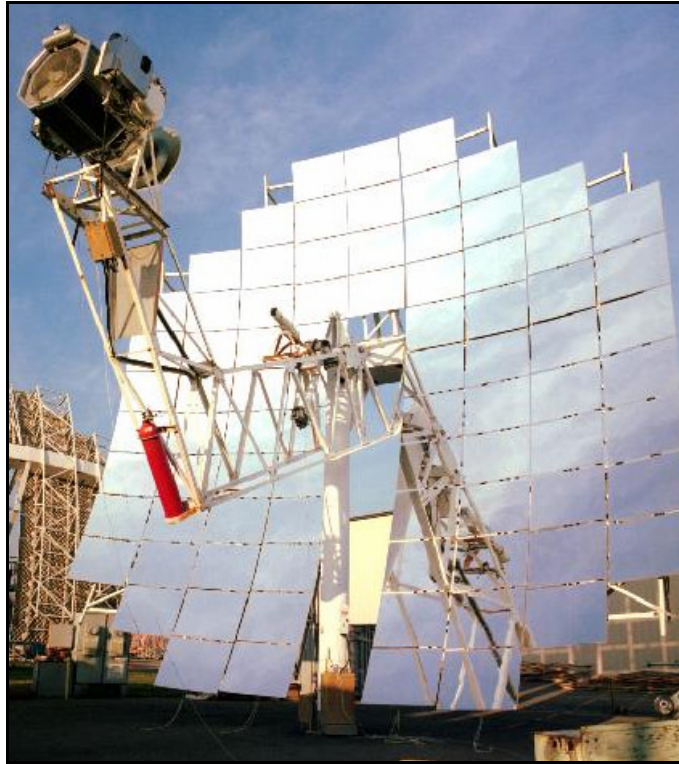


Figure 2-5
Dish-Stirling System

Solar dish-engine systems are being developed for use in emerging global markets for distributed generation, remote power, and grid-connected applications. Individual units, ranging in size from 10 to 25 kW, can operate independent of power grids in remote sunny locations to pump water or to provide electricity for people living in these areas. Largely because of their high efficiency and “conventional” construction, the cost of dish-engine systems is expected to be competitive in distributed markets. The engines are air cooled, eliminating the power plant cooling water requirement of the large, central power blocks associated with trough and power tower technologies. Thermal storage is not considered to be a viable option for dish-Stirling systems at this time.

There are no commercial dish-Stirling power plants operating today. Current development in the United States is focused on prototype system of 10 units in active development and testing at Sandia National Laboratories (SNL) under a joint agreement between Stirling Engine Systems (SES) (Phoenix) and Sandia. Additional prototype systems are planned prior to implementation of large-scale grid-connected systems.

Opportunities are emerging for the deployment of dish-engine systems in the southwest United States and internationally. Expected near-term deployments are as follows:

- Contracted deployments:
 - SES 25 kW demonstration dish, Eskom, South Africa.
 - 10 kW Schlaich Bergermann und Partner (SBP) dish providing power to grid in Spain.
- Proposed or planned deployments:
 - Six 25 kW SES dishes at the National Solar Thermal Test Facility (NSTTF), prototype testing.
 - One 10 kW SBP dish in France.
 - One 10 kW SBP dish in Italy.

2.1.5 Power Tower Systems

Power tower technology utilizes many large, sun-tracking mirrors (heliostats) to focus sunlight on a receiver at the top of a tower. A HTF heated in the receiver is used to generate steam, which, in turn, is used in a conventional turbine generator to produce electricity. Early power towers utilized steam as the HTF; the current US design utilizes molten nitrate salt because of its superior heat transfer and energy storage capabilities. Individual commercial plants will be sized to produce anywhere from 50 to 200 MW of electricity. Systems with air as the working fluid in the receiver or power system have also been explored in international research and development (R&D) programs. Figure 2-6 is a schematic diagram of the power tower technology. Figure 2-7 is a photograph of the 10 MW Solar Two prototype molten salt system.

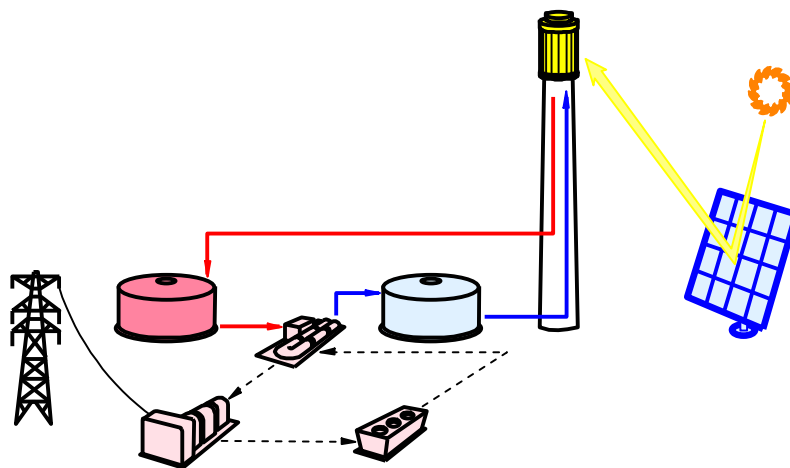


Figure 2-6
Power Tower System Schematic

The 10 MW Solar One plant near Barstow, California, demonstrated the viability of power towers, producing over 38 million kilowatt-hours (kWh) of electricity during its operation from 1982 to 1988. The Solar Two plant was a retrofit of Solar One to demonstrate the advantages of molten salt for heat transfer and thermal storage.

Utilizing its efficient molten-salt energy storage system, Solar Two successfully demonstrated efficient collection of solar energy and dispatch of electricity, including the ability to routinely produce electricity during cloudy weather and at night. The unit cost of thermal storage is lower in a tower system than in a trough system, and the reliable operation of the Solar Two thermal storage capability was an important result.

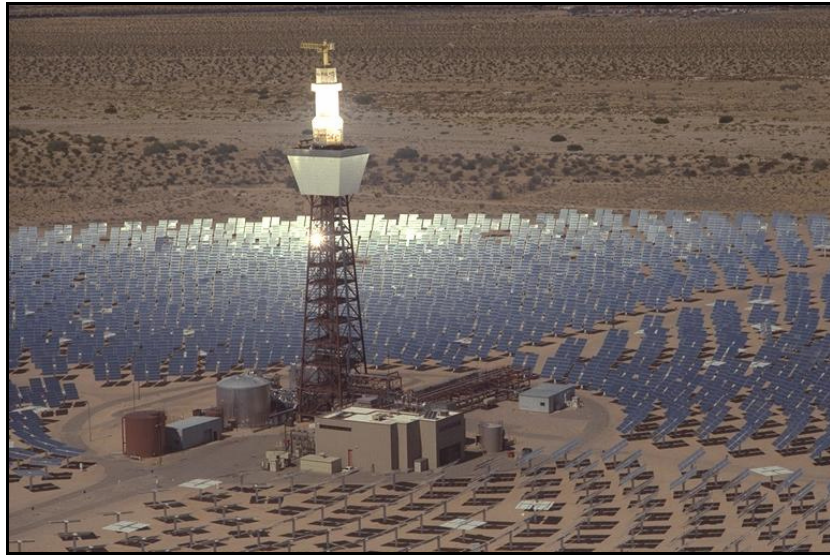


Figure 2-7
10 MW Solar Two Power Tower System

There are currently no commercial power tower plants in operation. Experimental and prototype systems have been placed in operation in Spain, France, Israel, and the United States, the largest of which were the two 10 MW systems previously described. While there are no definitive projects either contracted or confirmed, the following possibilities exist:

- ESKOM (South Africa), 100 MW Molten-Salt.
- PS 10 (Spain), Abengoa, 11 MW Air Receiver.
- Solar Tres (Spain), Ghera, Boeing, Nexant 17 MW Molten-Salt Plant.

2.1.6 CPV Systems

Concentration of solar radiation is also a promising approach for PV systems, because concentration reduces the cell area required to generate a desired electricity level. The use of concentration also suggests that higher efficiency, higher cost cells may

be the best economic choice for a system. Current technology is characterized by the following:

- 25 to 35 kW CPV systems.
- Two-axis tracking structure.
- 350 m² concentrator.
- 3M acrylic lens concentrator at 250x, or parabolic dish with PV at the focal point.
- Receiver utilizing inexpensive silicon solar cells, or advanced cell III-V multijunction technology.

Figures 2-8 and 2-9 are photographs of CPV systems offered by Amonix and Solar Systems Pty, Ltd, respectively.



Figure 2-8

Amonix: Flat Acrylic Lens Concentrator with Silicon Cells

A 50 MW CPV plant would consist of 2,000 25 kW systems, with modularity at a single 25 kW unit size. Similar to the dish-Stirling systems, no cooling water is required for operation. The solar-to-electric conversion efficiency is estimated to be about 16 percent with silicon cells, resulting in an annual capacity factor of 26 percent.

Near-term R&D is focused on reliability validation, module cost reduction (packaging), and advanced cell technology, e.g., III-V multijunction technology.

There are no commercial CPV power plants in operation. A series of pre-commercial development systems totaling 500 kW are operating in Arizona under the auspices of Arizona Public Service (APS), and a 200+ kW system is in operation in Australia. Planned deployments in the near future include 5 MW by APS, several MW in Australia, and an undetermined level in Europe.



Figure 2-9
Solar Systems Pty, Ltd: Parabolic Dish PV Concentrator

2.1.7 Dry Cooling for Heat Rejection in Trough or Power Tower Cycles

For Rankine cycle plants, cooling systems are required to condense the steam at the turbine exhaust and to maintain the design turbine back pressure. For a given ambient temperature and humidity, the size and effectiveness of the cooling system determines how low a condensing temperature can be maintained for a specified water flow. Wet systems use ocean, river, or pumped aquifer water in a mechanical draft wet cooling tower to perform this function.

In dry systems, the ultimate heat rejection to the environment is achieved with air-cooled equipment that discharges heat directly to the atmosphere by heating the air. Dry systems are of two types: direct and indirect. Direct systems duct the steam to air-cooled condensers that can be either mechanical or natural draft units. Indirect systems condense the steam in water-cooled surface condensers. The heated water is then pumped to air-cooled heat exchangers, where it is cooled and then re-circulated to the steam condenser. Dry systems reduce water use at a plant by eliminating the use of water for steam condensation. In most cases, the remaining water use, totaling perhaps 5 percent of the amount used in recirculating systems, is required for boiler make-up, other cooling applications, and the so-called “hotel load.” Dry systems increase the cost of electricity (COE) by virtue of a higher initial capital cost, a degradation in turbine performance during periods when the turbine backpressure is increased because the condensing temperature rises, and an increase in plant parasitic power requirements due to the air fans in mechanical draft systems. However, the infrastructure for pumping and conditioning the very high water flows in wet systems is eliminated, as are the evaporation ponds or other means to contain the waste products (sludge).

Conclusions about the relative cost of wet versus dry cooling are difficult to generalize, and depend on many site-specific considerations. “Conventional wisdom” holds that the capital cost might increase by approximately 3 to 6 percent, and performance might be reduced by about 5 to 9 percent. A general rule of thumb is that the COE can increase up to 10 percent. However, the effects can vary considerably depending on site factors and system configuration.

For this feasibility study, an in-depth evaluation for the Electric Power Research Institute and the California energy Commission¹ was utilized to modify the National Renewable Energy Laboratory (NREL) parabolic trough solar plant performance/cost model to include dry cooling as an option. These changes estimate the investment costs, operating costs, and performance effects due to the addition of a dry cooling system. The projected impact on levelized electricity cost was less than 5 percent in the cases evaluated for this study. Given the uncertainty associated with this result, and the likelihood that dry cooling will be highly valued for a solar system operating in New Mexico, we recommend that this topic be given high priority in future work.

2.2 Effectiveness of Thermal Storage

Electricity demand in New Mexico, due to residential, commercial, and industrial use, tends to peak during summer afternoons and evenings and winter evenings. Figure 2-10 illustrates the total demand from 2002 records, showing average days for each month. The demand is highest in June, July, and August, largely due to air-conditioning usage. The figure shows average daily capacity by month for Public Service Company of New Mexico (PNM).

Solar system output tends to match the morning and afternoon demand but falls off in late afternoon. Thermal storage permits collecting solar energy during one period and shifting its use to a later time. That is, energy collected in the afternoon could be used to generate electricity in the evening, if desired. If the solar field size is also enlarged in the system, the addition of thermal storage also results in a large solar electrical capacity factor for the plant. These results are applicable for power tower and trough systems, because thermal storage is not currently anticipated for dish-Stirling units. CPV systems cannot use thermal storage (although more expensive battery energy storage could be used).

¹ Comparison of Alternate Cooling Technologies for California Power Plants: Economic, Environmental, and Other Tradeoffs, EPRI, Palo Alto, CA, and California Energy Commission, Sacramento, CA: 2002.

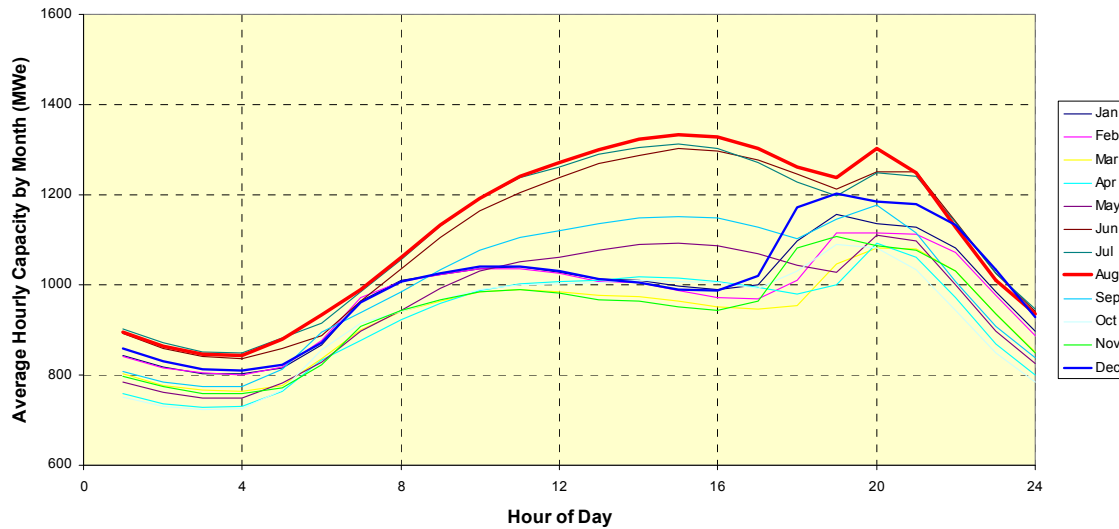
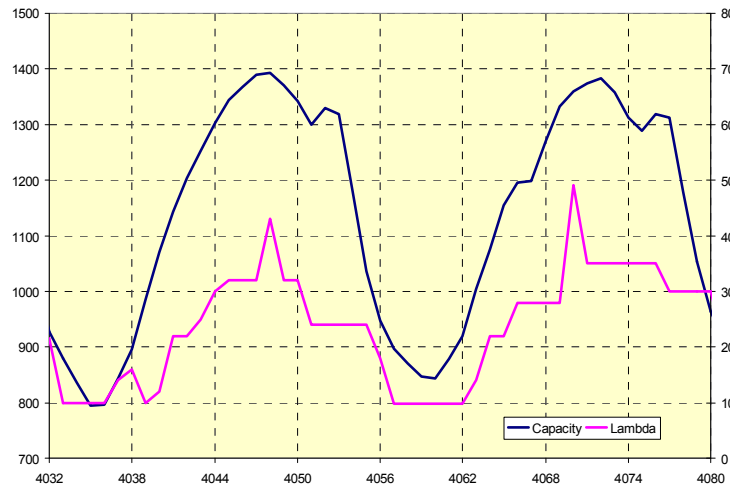


Figure 2-10
Average Daily Capacity by Month
Public Service Company of New Mexico

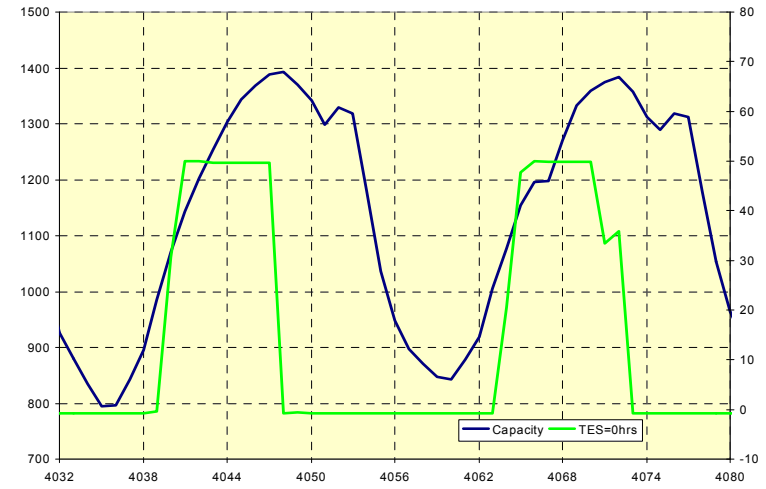
An analysis was carried out to quantify the effect of thermal storage on the ability to match demand for a typical June day. The capacity of the storage system is characterized in terms of the equivalent full-load electrical generation that it can shift. The graphs on Figure 2-11 show the results. Each plot shows two full days for clarity. The upper left plot shows the system demand and the relative value of the electricity, which tends to track the demand. The system demand curve is replicated on the other plots, which show the solar system output patterns for solar systems with no storage; 6 hours' storage; and 6, 9, and 12 hours' storage shown on the same plot (lower right).

These results suggest that 6 hours' thermal storage is suitable for matching New Mexico demand. To explore this further, several other parametrics were examined as a function of storage capacity. These include the annual capacity factor, the peak day capacity factor, the relative levelized electricity cost (which takes both performance and system cost into account), and the peak summer day capacity factor. Results of this analysis are summarized on Figure 2-12. Based on these results, a 6 hours' storage system was selected for subsequent cost and performance analysis.

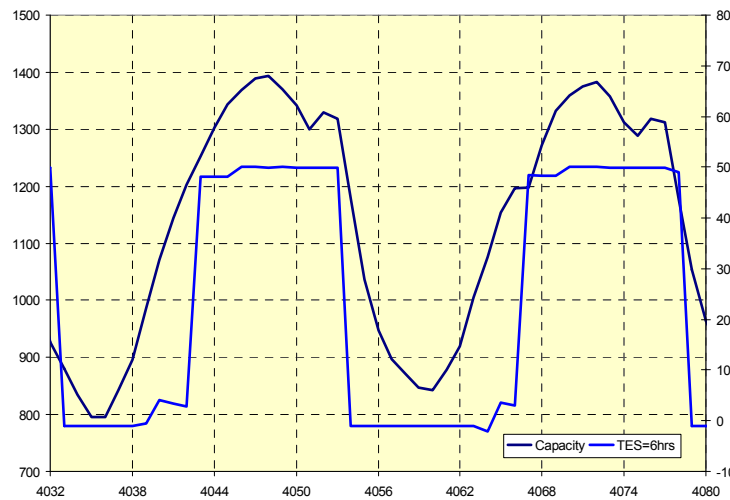
System Electricity Demand and Price



Solar Output with No Storage



Solar Output with 6 hours Storage



Solar Output with 6-9-12 Storage

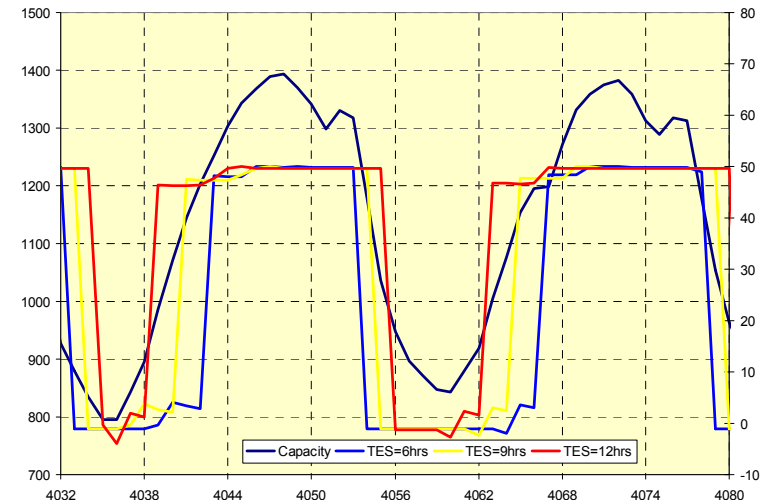


Figure 2-11
Comparison of Solar Plant Output with Various Storage Capacities Versus Load

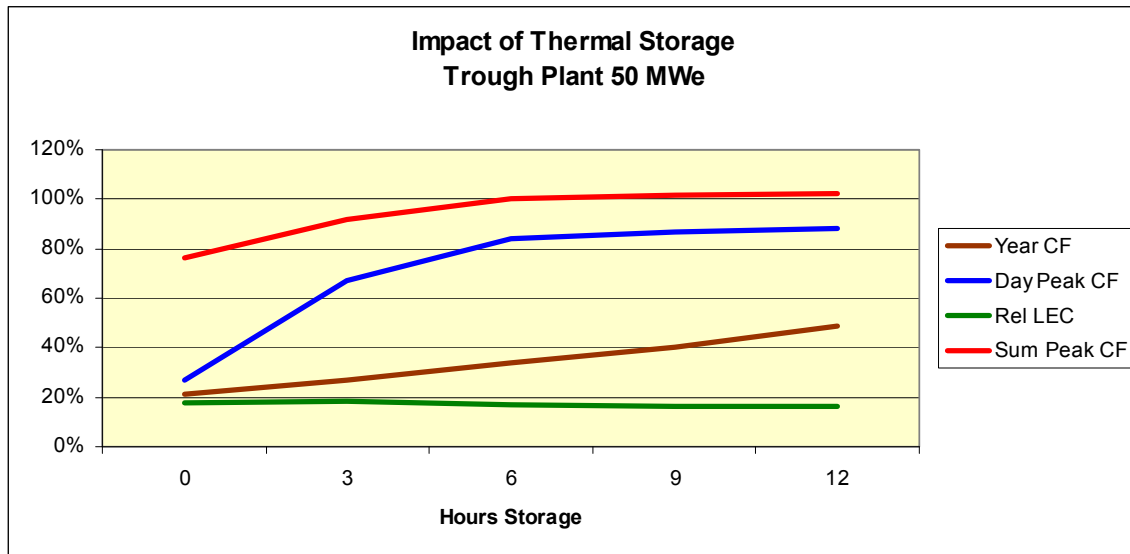


Figure 2-12
Impact of Thermal Storage on 50 MW Trough Plant

2.3 Scope and Methodology of the Evaluation

The technology factors that were taken into account in the technology assessment and subsequent evaluation (e.g., siting) include the following:

- Development status.
- Risk assessment.
- Equity requirements.
- Water use issues, including dry cooling.
- Equipment reliability.
- Storage options for 6 hours' operation.
- O&M costs.
- Effect on siting requirements.
- Industry capability and depth.
- Performance.
- Cost of Energy.
- Transmission considerations.

These factors were considered when judgments were made about the four technologies concerning the following major issues:

- Characterization of commercial readiness.
- Characterization of technology risks.

- Estimate of current costs.
- Future cost projections, dependent on deployment scenarios.

The approach taken in this evaluation was to strive for objective, independent conclusions based on available data and reasonable judgments, including cost and performance data derived from SunLab estimates or vendor feedback, scrutinized from the viewpoint of the B&V team's experience.

To this end, specific criteria were established for judging the technical status and readiness of a technology for purposes of this assessment. These criteria include timing, qualification, and other factors such as water use, and compatibility with thermal storage, as discussed in the following sections.

2.2.1 Timing

- The plant must be capable of startup by the end of 2007.
- This means, with a 2 year development cycle (design; procure; construct; startup) the following must occur.
 - New Mexico to issue request for proposal (RFP) for solar plant by approximately mid-2005.
 - Award project by late 2005.
- To be eligible for selection in this evaluation, technology must be judged to be qualified for project development by mid-2005.

2.2.2 Qualification

The technology must be ready for commercial project development at 50 MW or larger plant capacity. Key questions relevant to this issue include the following:

- Has the technology operated at commercial prototype system scale?
 - Has it operated with good performance?
 - Has it shown high reliability?
- Are there any major technology barriers at large scale?
- Are there qualified developers and equipment suppliers?

2.2.3 Other Important Factors

- What are water requirements?
- Is thermal storage an option?

The key metrics in this evaluation are performance, cost, and reliability. As renewable energy projects with limited commercial experience, important characteristics to be examined include the following:

- Use of nonconventional critical components.
- Existence of an established supplier pool (single or multiple).
- Scope and issues related, at this point in the development, to solar system warranty.

2.4 Development Status of Main CSP Technology Options

In this section, conclusions are presented on the development status of the four CSP technologies under primary consideration in this feasibility study; these technologies are then evaluated for their suitability as a candidate for a 50 MW plant to be operational by late 2007.

This last point is critical. The judgments expressed are strongly tied to the criteria discussed in Section 2.3. That is, the primary criteria are as follows:

- Demonstration of sufficient commercial operation showing reliability and acceptable performance.
- No major technology barriers at large scale.
- Qualified developers and equipment suppliers.

In addition, the following perspectives must be emphasized:

- A recommendation for 2007 operation in New Mexico is not a judgment on the promise of any of the technologies for future success.
- Regardless of the technologies chosen here for evaluation at identified sites, it is expected that the RFP process for a solar plant will be unrestricted with regard to solar thermal technology type, allowing any developer to propose a commercial project.

Based on the evaluation criteria applied to each technology, only parabolic troughs were judged suitable for commercial operation in the time frame under consideration. This judgment acknowledges parabolic troughs as an emerging mature commercial technology as evidenced by a cumulative deployment to date of 354 MW and their demonstrably acceptable performance at the Kramer Junction site.

2.4.1 Parabolic Trough Systems

Parabolic trough systems are considered commercially available for industrial applications. The primary developers of this technology include Solargenix Energy (USA), Solel Solar Systems (Israel), and Solar Millennium (Germany). Suppliers of

components for trough systems include reflector supplier Flabeg (Germany) and receiver suppliers Schott Glass (Germany) and Solel Solar Systems.

For thermal storage, the preferred technology is the molten salt two-tank system. This provides a feasible storage capacity of up to 12 hours and is considered to have a low-to-moderate associated risk.

Water requirements depend on the design and configuration of the trough system. If wet cooling is used, water consumption is about 2.8 m³/MWh, similar to conventional steam plants; in addition, about 0.14 m³/MWh of water is needed for washing the solar field. Dry cooling reduces water consumption drastically, but also reduces performance and increases cost.

Siting requirements for a parabolic trough system include level land, with less than 1 percent slope desirable. Solar fields are typically graded in two or more terraces for a full plant. The cost for grading is a small portion of the total cost.

Table 2-1 provides key characteristics for 50 MW, 100 MW, and 4 x 100 MW parabolic trough systems. Cost and performance uncertainties for troughs are judged to be relatively low.

Table 2-1 Parabolic Trough System Characteristics			
Capacity	50 MW	100 MW	4 x 100 MW
Storage	6 hours	6 hours	6 hours
Annual Efficiency, %	12.3	12.5	12.5
Land Area, km ²	1.6	3.2	8.0
Collector Mirror Area, m ²	482,000 m ²	959,000 m ²	3,536,000 m ²
Annual Capacity Factor, %	34	34	34
Direct Cost, \$M	185	348	1,180
Direct Cost, \$/kW	3,710	3,460	2,950
Annual O&M, c/kWh	3.0	2.2	1.9

2.4.2 Dish-Stirling Systems

Dish-Stirling systems are considered to be in the developmental stage. To date, there are less than 10 prototype units in service. System developers include SES (USA) for 25 kW units, and SBP (Germany) for 10 kW units. Components are currently acquired from a few suppliers, with several more identified as potential suppliers. System developers are currently using a Denver-area reflector supplier for low volume production; however, developers are in discussion with several alternative suppliers of

mirror facets manufactured in the United States, Europe, and Asia for high volume requirements. The SES PCU is a Kockums 4-95 Stirling engine. SES notes that many potential PCU component suppliers exist throughout the United States. Assembly, testing, and warranty services are provided by a Detroit-area engine manufacturer.

There are no thermal storage options currently available for dish-Stirling systems. The systems are air cooled, and the low water requirements are associated with mirror washing and service water. Level land is preferable for construction and maintenance ease; however, siting requirements on slope are likely less significant than those for trough and tower systems.

Technology costs are based on developer-supplied data for 2007 deployment and are judged as having high uncertainty because of the early production stage of this technology (there are less than 10 prototype units to date).

Table 2-2 provides costs per kW provided by SES for a first 50 MW dish system and for a 50 MW system that is part of a total deployment of 300 MW or more. The uncertainty on these cost numbers is considered to be quite large.

Table 2-2 Dish-Stirling Costs Versus Production		
Capacity	Number of Units	Cost
50 MW	2,000	\$2,550/kW
50 MW, combined with 300+ MW for other plants	14,000	\$1,500/kW
Source: SES.		

2.4.3 Power Tower Systems

The power tower system is considered to be pre-commercial at a 10 MW scale. No specific project developers have been identified; however, component suppliers include heliostat supplier Sener and Inabensa in Spain, and molten-salt system supplier Boeing in the United States.

These systems are well suited for thermal storage; the molten-salt two-tank system is inherent to the power tower design and can feasibly provide up to 16 hours of high-efficiency storage at a low-to-moderate risk.

Cooling water requirements are about 2.8 m³/h per MW, which include a small amount for heliostat washing. Dry cooling reduces this water consumption drastically, although, as with the trough system, performance is reduced and cost increased.

As with the trough system, level land is preferable, with less than 1 percent slope desirable. The land area must be one continuous parcel with essentially a circular footprint.

Table 2-3 provides cost and performance characteristics for 50 MW, 100 MW, and 200 MW power tower systems. The cost and performance uncertainties are considered to be relatively high.

Table 2-3 Power Tower System Characteristics			
Capacity	50 MW	100 MW	200 MW
Storage, hours	6	6	6
Annual Efficiency, %	14.3	14.4	14.5
Land Area, km ²	2.1	4.4	9.1
Mirror Area, m ²	462,000	918,000	1,824,000
Annual Capacity Factor, %	38	38	38
Direct Cost, \$M	189	349	600
Direct Cost, \$/kW	3,770	3,490	3,000
O&M, c/kWh	3.0	2.2	1.9

2.4.4 CPV Systems

CPV systems are considered to be developmental; no specific project developers have been identified. System suppliers include Amonix, based in Torrance, California, and Solar Systems Pty, Ltd., based in Hawthorne, Victoria, Australia. There are several existing component suppliers, including several cell suppliers such as Emcore, Spectrolabs, and Sun Power.

Amonix uses a Fresnel lens concentrator to achieve systems that generate 25 to 35 kW at an average efficiency of 15.5 percent. Amonix systems have been deployed at APS facilities for a total capacity of 547 kW. Currently, the systems use high-efficiency silicon cells. Efficiency and capacity gains are expected with advance triple-junction cells and higher concentration.

Solar Systems Pty, Ltd., offers a 24 kW system that averages about 15 to 16 percent efficiency. The design incorporates a parabolic dish concentrator with the PV receiver at the focal point and features active cooling of the receiver. Ten dishes have been deployed since 2003, for a total capacity of 220 kW, with the construction of an additional 720 kW under way. Several MW of contracts are anticipated in the relatively near future. The next generation of higher efficiency CPV modules is expected to

increase the capacity to 35 kW in 2005. The core CPV technology, which accounts for about 25 percent of the cost, would be manufactured in Australia, with the remainder to be manufactured in the United States.

Similar to the dish systems, level land is preferable for construction and maintenance ease, although it is likely a less significant requirement for CPV sites than that required by trough and tower systems.

Because of the relatively low deployment of CPV systems, the cost for 50 MW in 2007 is not available. For the long term, with multijunction cells currently under development, suppliers' project costs could approach \$2,000/kW.

2.4.5 Summary of Evaluation of Suitability for 50 MW Deployment in 2007

Table 2-4 summarizes the evaluation of the suitability of trough, dish-Stirling, power tower, and CPV technology for 50 MW deployment in New Mexico in 2007. Overall, the assessment concludes that only the parabolic trough technology is commercially viable in the 50 MW or larger size range by 2007.

Table 2-5 provides an assessment of risk for a 2007 commercial deployment of a 50 MW plant.

2.5 Other CSP Technology or Repowering Options

Several other solar thermal electric systems or configurations have been proposed for CSP applications. The following CSP options are discussed briefly in this section:

- Repowering--The use of a solar system to provide thermal energy to an existing power facility. Typical applications include the following:
 - Boiler feedwater heating.
 - Solar steam generation (with or without superheat) to augment or replace the boiler in a conventional steam plant.
 - Combining a parabolic trough field with a combustion turbine (CT).
- Solar Combined Cycle--Integrating a power tower or trough solar field with a CT, a heat recovery steam generator (HRSG), and a steam turbine to form a combined cycle plant.
- Compact Linear Fresnel Lens (CLFR) Technology--A new technology in prototype operation in Australia.

Table 2-4
Suitability for 50 MW Deployment

Technology	Commercial Status	Developer/Supplier Status	Water Requirement	Thermal Storage	Deployment Feasibility
Parabolic Trough	Firm basis of commercial operation for 50 MW deployment	Three system supplier/developer companies active. Supply pool of unique components limited but growing.	Large if wet cooling; relatively low with dry cooling	Molten-salt; presently in pre-commercial status	Ready for 50 MW deployment in New Mexico in 2007.
Dish-Stirling	Lack of commercial operation in scales approaching MW capacity	Sole source supply for 25 kW system (SES). Current prototype development at SNL offers potential for progress on design and reliability.	Low	Not available (does not apply)	A 50 MW deployment in New Mexico in 2007 would be challenging and would require large commercial deployment from present prototype systems.
Power Tower	10 MW scale prototype testing at Solar Two valuable, identifying several technical issues for further resolution. Chosen by Eskom for possible project.	Boeing ready to supply and guarantee molten-salt system components: receiver, thermal storage, and steam generator.	Large if wet cooling; relatively low with dry cooling	Molten salt	A 50 MW deployment in New Mexico in 2007 would be challenging.
CPV	Lack of commercial operation in scales approaching MW capacity. CPV system designs appear to be sound; system efficiency increases require successful multijunction cell development (ongoing).	System supplier pool is limited at present.	Low	Not available (does not apply)	A 50 MW deployment in New Mexico in 2007 would be challenging and would require large commercial deployment from present prototype systems.

Table 2-5
Technology Risk Assessment Chart*
(For 2007 Commercial Deployment of 50 MW Plant)

Technology									
	What are non-conventional components?	What is the risk of performance specifications being met at high reliability?				Multiple Equip. Vendors?	Meet 2007 performance?	Meet 2007 cost estimates?	Warranty risk?
	Receiver	Reflector	Structure	Power Unit	Storage				
Trough-storage	Moderate	Low	Low	Low	Moderate	Adequate	Risk low	Risk low	Risk low-mod
Trough-hybrid	Moderate	Low	Low	Low	NA	Adequate	Risk low	Risk low	Risk low-mod
PowerTower-Salt	Moderate-High	Low	Low-Moderate	Low	Moderate	Limited	Risk mod	Risk mod	Risk mod-high
Dish-Stirling	Moderate	Moderate	Moderate	Mod-high	NA	Limited	Risk high	Risk high	Risk high
CPV	Silicon cell package: Low	Concentrator Low - Mod	Low	Inverter: Low-Mod	NA	Limited	Risk mod	Risk high	Risk high
*Risk is assessed as high, moderate, or low from large commercial system view.									

2.5.1 Repowering

Both parabolic trough and power tower are suited for producing the required thermal energy for repowering applications. Issues with this application include the effective electrical capacity of the solar contribution and the true cost of the solar contribution.

Boiler feedwater heating is a primary application being considered for repowering. This is conventionally accomplished by turbine steam extraction. With solar heating of the feedwater, turbine steam used for extractions would then expand in the turbine and increase the electrical output. However, there are several issues to be evaluated, requiring an in-depth engineering and cycle analysis. These issues include the following:

- A turbine is limited on maximum steam flow, so that typically only one or two extractions can be shut down.
- Feedwater heating by extraction raises cycle efficiency, and replacement by expensive solar energy may not be cost effective.
- Cycle analysis using a tool like GateCycle is needed to adequately evaluate proposed configurations.

Combining a solar trough plant bottoming cycle with a combustion engine is discussed in Subsection 2.5.4.

2.5.2 ISCCS

This concept adds a solar field to a combined cycle plant to generate saturated steam that is fed to the HRSG for high temperature superheat or reheat and then sent to the steam turbine. A typical combined cycle has a steam turbine of about half the capacity of the CT. In an ISCCS concept, the steam turbine capacity would be increased to accept solar steam.

Overall solar contributions are small, less than 10 percent at design point, and less than or equal to 3 percent annually. Combined cycle and solar fields are “conventional,” but the redesign of the HRSG and a new control scenario bring moderate risk to the concept. No hardware or commercial experience exists to date. This technology is not recommended for New Mexico at this stage of development.

2.5.3 CLFR Technology

This technology has been developed by Solar Heat and Power of Australia. The collector field in this design consists of slat-type linear mirror assemblies reflecting light to the CLFR receiver, where a Fresnel lens concentrates solar radiation. This provides direct steam generation from the solar field at 86 bar/300° C. CLFR is best suited to

drive large, low-pressure steam turbines (greater than 200 MW), such as those used in large nuclear cycles. The developer estimates low power block, collector, and O&M costs.

CLFR is in the early prototype stage, and the initial performance results reportedly match projections, although there is a lack of independent validation on performance and cost. The costs associated with the solar field are potentially low relative to higher efficiency technologies.

The water requirements for this technology are relatively higher due to the lower efficiency of the Rankine cycle.

Over the period of 2004 to 2005, a 20 MW system will begin operation in Australia, followed immediately by a second 20 MW expansion. A 250 MW system is planned, to take advantage of large, low-pressure, low-cost steam turbines (e.g., nuclear). A 50 MW deployment in New Mexico in 2007 would be challenging and would require large commercial deployment from the present prototype system.

2.5.4 Combining Solar Trough Plant Bottoming Cycle with a CT

One developer, Markron Technologies Inc., has proposed the concept of adding a bottoming cycle to a peaking CT installation, whereby the CT exhaust gas would be used to superheat the solar-generated steam and provide feedwater heating. With this configuration, both the CT and solar plant can be run independently, since CT operation is not affected by the presence of the solar system. If the CT is not operating, the solar system functions with lower superheat (similar to the power block design at SEGS 3-7). A system schematic for this system is shown on Figure 2-13.

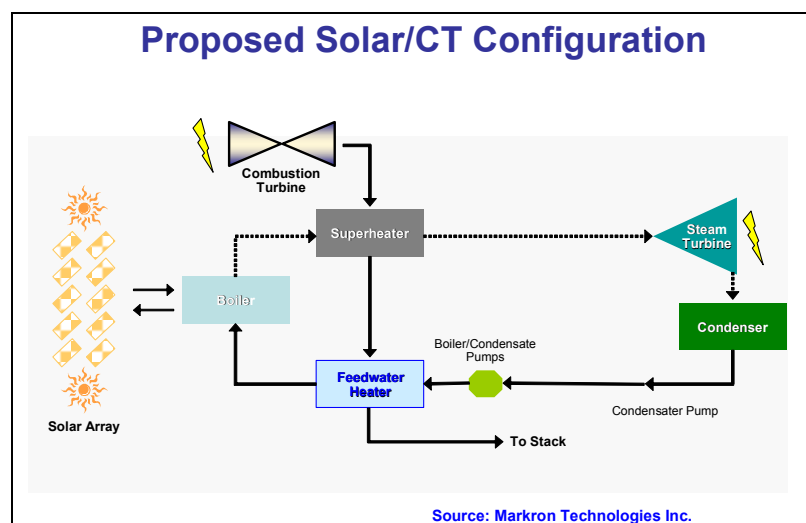


Figure 2-13
Solar/CT Configuration

During operation, solar steam is generated at 900 psia/700° F at a mass flow of 3,000 lb/h. For a 40 MW LM6000 CT, the exhaust is typically at 1,000,800 lb/h at 850° F. Solar steam can be superheated to 810° F using the CT exhaust gas. A steam turbine of 54 MW gross generates approximately 36 MW from solar input and 18 MW from superheat/feedwater heating by CT exhaust.

A preliminary assessment of the CTs operating in areas of New Mexico with suitable site characteristics finds the following:

- 240 MW of CTs, mostly 40 MW capacity.
- A solar system maximum potential of about 210 MW.
- A total peak potential (including CT and exhaust gas added to solar system output) of about 550 MW.

The candidate plants identified in the developers' estimate differ somewhat from these initial numbers, highlighting the preliminary nature of these projections.

Solar plants would be relatively small, resulting in a large per MW cost, suggesting that a single solar plant might best operate with multiple gas turbines. Independent cycle, solar performance, and cost analyses were not undertaken in this feasibility study; these analyses are necessary for confidence in the developers' estimates. The steps required for further independent evaluation of the concept would include the following, at a minimum:

- Identification of all New Mexico power plants eligible for repowering, sorted by capacity, age, fuel, and location.
- Evaluation of solar system siting potential at sites of eligible plants.
- Evaluation of transmission capacity.
- Recognition that solar system size has a strong influence on unit solar field cost (\$/m² of solar field), solar system O&M costs, and the steam Rankine bottoming cycle cost.
- Selection of the best candidates for solar repowering.

3.0 State Siting Assessment

The objective of the state siting assessment was to identify and evaluate at least three sites for 50 MW or larger plants in New Mexico, to consider appropriate technologies at candidate sites, and to provide a preliminary estimation of site-related costs. It must be emphasized that this assessment was preliminary in nature and was intended to support the overall objectives of the study rather than to identify specific tracts of land owned by any specific landowner. Furthermore, the assessment should not be considered exhaustive; it is likely that there are viable sites not identified in this task. This assessment has provided the B&V team with necessary information on which to base development model scenarios to assist the state in its consideration of incentive packages and to provide a broad roadmap for future project developers.

3.1 Site Requirements

The site assessment has included consideration of the following elements:

- Solar resource.
- Adequate land and topography (typically less than 1 percent slope).
- Transmission issues.
- Land ownership.
- Water resource.
- Economic benefits/costs.
- Environmental/permitting considerations.
- Sociological/political issues.

Solar resource is a key decision element for determining the appropriate sites. In this study, only those sites having annual direct normal insolation (DNI), which is that portion of solar radiation coming directly from the sun) ≥ 6.75 kW/m²/day were considered. New Mexico has large areas of land with DNI exceeding 6.75 kW/m²/day and has some areas with DNI exceeding 7.5 kW/m²/day. Annual electrical energy generation is nearly proportional to available DNI, and COE is generally inversely proportional to DNI.

A second key requirement is adequate land and topography. The land area required by a 50 MW solar plant with 6 hours of storage is about 400 acres. Parabolic trough and power tower plants require land that has a slope of less than 1 percent (i.e., 1 foot rise per each 100 feet lateral distance). Parabolic dish and CPV systems could have slightly greater land slopes. Relatively flat areas of land with sufficient acreage, which did not have significant residential or commercial development, and which did not appear to be in an obvious floodplain were considered for evaluation.

The availability of adequate transmission to appropriate load centers is another key element for siting a solar plant. A load flow analysis of transmission systems was outside the scope of the project. Therefore, information from transmission experts from the state's investor-owned utilities was used, as discussed below. It must be emphasized that the information provided, and the basis for this assessment, is qualitative, and is based on judgments. A solar plant project development effort would require appropriate load flow analyses performed by appropriate transmission system owners.

Land in New Mexico is typically owned by private parties, the state, or the federal government (Bureau of Land Management [BLM], Indian reservation, military reservations, Forest Service, parks). In general, land ownership was not used as a siting criterion, other than to avoid urban areas and parks.

All four of the CSP technologies use a limited amount of water for the washing of mirrors or Fresnel lenses. Parabolic trough and power tower plants, which use wet cooling towers for heat rejection, use a water amount of about 2.8 m³ per MWh, which is comparable, on a per MWh of electricity generated basis, to coal fueled power plants. As a result, water availability was qualitatively evaluated. Cost/performance numbers were also developed for a 50 MW parabolic trough plant using dry cooling.

Candidate sites must not have environmental or permitting constraints, nor should they have other sociological or political hurdles that would make the development of the site impossible or overly difficult. As discussed below, Internet searches of endangered species and cultural properties for preferred sites were performed.

An additional consideration has been visual impact/public accessibility. In general, the visual impact is not considered a particularly negative factor. In fact, visibility and access, including an education visitor's center, could be a significant plus for a project.

Evaluation of economic benefits versus costs has been limited to the evaluations discussed in Section 7.0, including the companion study performed by the University of New Mexico BBER.

3.2 Siting Approach

The approach taken in performing the siting assessment is illustrated on Figure 3-1. The team started with the NREL/Platts New Mexico Solar Siting Study.² That study had performed a broad geographic information systems (GIS)-based evaluation of solar resource, topography, and transmission, resulting in the identification of two large areas, Location 1 in central New Mexico and Location 2 in southwest New

² Solar Power in New Mexico: Power Market Background and Siting Analysis, Prepared by the NREL and Platts, February 2004.

Mexico. Two parallel and interactive tasks were undertaken. Platts, working with NREL, performed a refinement of the NREL/Platts study using a finer grid, requiring land areas to have less than 1 percent slope, and requiring locations to be within 10 miles of major transmission lines.

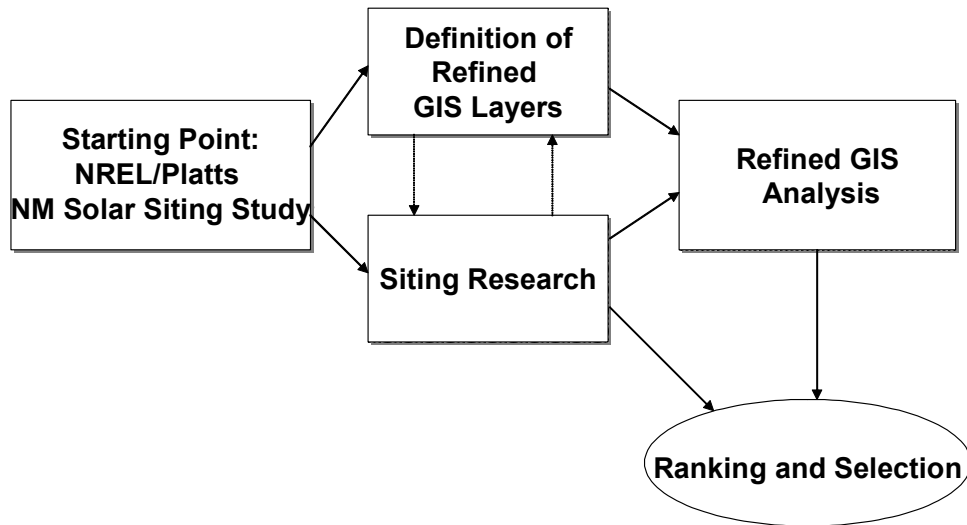


Figure 3-1
Site Assessment Approach

Because of the importance of transmission issues, early in the project the team met with transmission experts from four investor-owned utilities in New Mexico to discuss potential constraints and to identify preferred areas from a transmission/load perspective. The utilities that were met and communicated with over the duration of this project have been PNM, El Paso Electric Company, Excel Energy, and Texas-New Mexico Power Company. Several discussions were also held with Tri-State Generation and Transmission Association.

During the assessment, the team reviewed topographical maps of the area to identify areas with particular potential. A key step in the siting assessment was a reconnaissance driving trip of more than 1,000 miles over a 2 day period. The approach and findings of that trip are discussed in further detail later in this section.

As a result of the site reconnaissance trip, nine candidate sites were identified (discussed in Section 3.5). From these nine sites, five were selected for closer evaluation. These five sites are discussed in more detail in Section 3.5. From these five sites, three were selected as recommended sites that have been carried forward for evaluation in subsequent tasks.

3.3 Initial Map Refinement

Figure 3-2 shows the result of the initial GIS map refinement performed by Platts interacting with NREL. This map shows the preferred regions, Location 1 and Location 2, that have significant areas within them with a combination of high solar resource, relatively flat land, and proximity to transmission lines. Figure 3-3 provides enlargements of Locations 1 and 2.

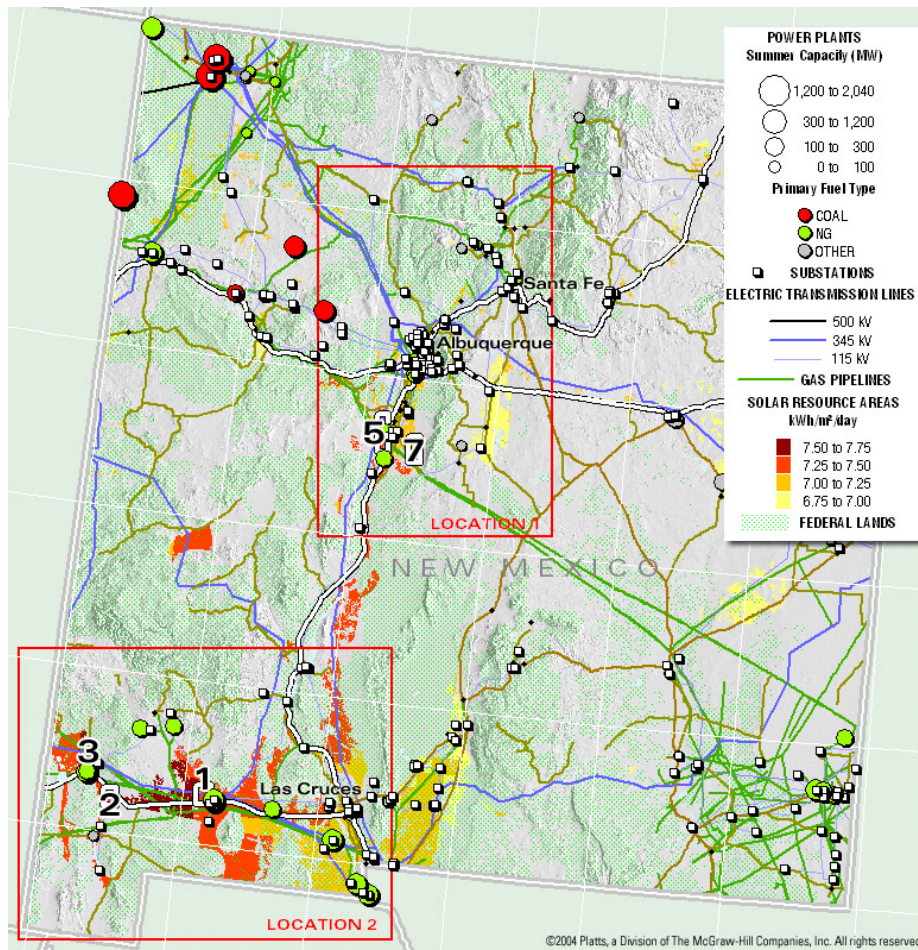
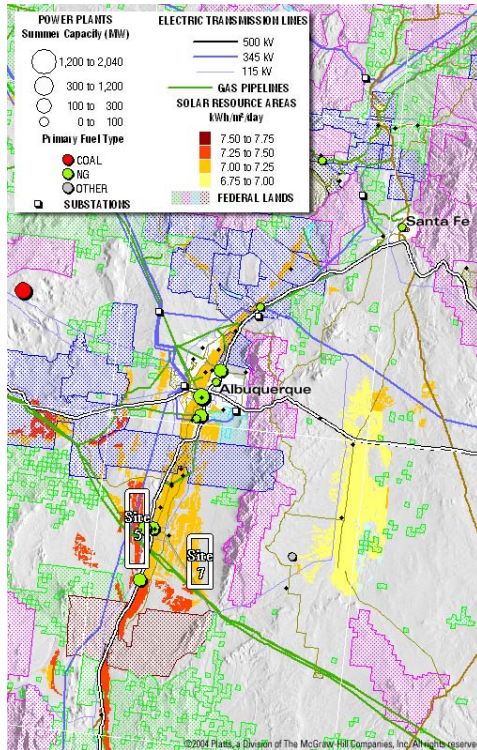


Figure 3-2
GIS Map of New Mexico Showing Locations 1 and 2

Location 1



Location 2

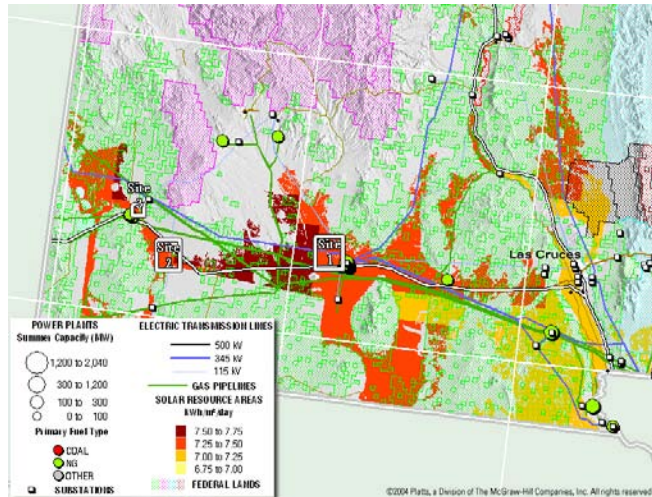


Figure 3-3
GIS Detail for Locations 1 and 2

3.4 Site Reconnaissance

On October 13 through 15, 2004, two members of the team drove approximately 1,000 miles in New Mexico, visiting potential sites in Locations 1 and 2. In general, focus was on those areas that had been recommended by the IOU transmission specialists and that, through the GIS analysis and review of topographical maps, appeared to have significant potential. However, some areas were also visited that had appropriate land characteristics and that, from the transmission maps, included major transmission lines and substations. Typically, the reconnaissance was from roads; specific tracts of land were not visited by walking. Visual confirmation of land topography and degree of development was made, and any obvious hindrances to solar plant development were identified.

3.5 Identified Sites

As a result of the reconnaissance trip, eight candidate sites were identified. A ninth candidate site is US Department of Energy (DOE) excess land. No visit was made to this site, but discussions were held with the DOE.

Table 3-1 presents a summary of the nine candidate sites, including pertinent information.

3.6 Preferred Sites

Five of the nine sites identified in the reconnaissance trip were selected as preferred sites for further evaluation. The locations are illustrated on Figure 3-4. Sites that were not selected for further analyses included the following:

- Site 4, northeast of Deming on Highway 26. Eliminated because of transmission constraints on the nearby 115 kV line.
- Site 6, west of Los Lomas, partly on Isleta Indian Reservation. This site is really the northern end of Site 5. For purposes of this evaluation, they have been included as one area.
- Site 8, vicinity of Willard to Estancia, along Highway 41. Eliminated because other sites have better solar resource and better transmission capability.
- Bluewater Disposal Lands (DOE property). Eliminated because other sites have better solar resource and better transmission capability.

The following subsections discuss the five preferred sites in more detail. It should be emphasized that the sites identified in this study are representative of good locations in New Mexico. Developers may identify other sites whose characteristics are more attractive to the specific project being developed.

3.6.1 Site 1: Northwest of Deming

Site 1 is a 38 square mile area in Luna County, just northwest of Deming, to the north of Interstate Highway 10 and west of Highway 180. A GIS rendition of the Site 1 area is shown on Figure 3-5. The site is near PNM's Luna Substation, which is a key 115 kV/345 kV hub for transmission in southwest New Mexico. The intent is that the plant would connect to the substation at the 115 kV hub. A topographical map of a portion of the area close to the Luna Substation is shown on Figure 3-6. The site under consideration could extend for several miles to the west, with connection via a 115 kV, project-owned transmission line.

The site is near the Deming Energy Facility, a 2 x 1 GE 7FA gas fired combined cycle plant, which has been under construction by Duke Energy. Duke suspended construction of the plant, which was to be a merchant plant, at about 40 percent completion due to electricity market conditions. A recent announcement has been made, since the completion of this siting assessment, indicating that PNM, Phelps Dodge, and Tucson Electric Power (TEP) have purchased the plant from Duke and plan to complete construction. It is expected that construction, once restarted, could be completed in 12 to 18 months.

Table 3-1 Site Matrix for Nine Identified Sites											
Site ID	Location Description	Nominal Latitude (North)	Nominal Longitude (West)	County	Area Square Miles	Solar Resource (kW/m²/day)	Topography	Transmission/Substation Information	Water Availability	Land Ownership	Comments
1	Northwest of Deming. West of Luna Substation Area	32.314	107.803	Luna	38	7.5	Large expanses of generally flat, level land. Slopes generally less than 1 percent, sloping downward in a southeast direction. Grubbing required.	Luna Substation. Would connect at 115 kV.	No surface water. Groundwater dependent on acquiring water rights. Deming gray water being used by delayed 600 MW Duke Energy Plant.	Private/State	Close to major substation. Reports of high winds and dust. Hwy warning signs near substation warn of low visibility during dust storms. Generally flat with sage and scrub brush. Some irrigated farmland within area.
2	South of I-10 Exit 34 on Hwy 113.	32.265	108.552	Hidalgo/Grant	30	7.5	Large expanses of generally flat, level land. Slopes in most likely solar plant area are about 1/2 percent, generally downward in westerly direction. Minimal grubbing required.	Vicinity of Tri-State Pyramid Plant and substation. Would likely connect to substation at 115 kV for transmission to Hidalgo 115 kV/ 345 kV Substation.	Lower Colorado River Basin. Surface water unknown. Reasonable potential for groundwater.	Private/State	Near 115 kV transmission line. Near I-10 interchange, so high public visibility. Flat land, grazing.
3	North of Lordsburg Power Plant/Substation	32.375	108.693	Hidalgo	6.1	7.5	Adequate land, slopes in 1.0 to 1.5 percent range, sloping downward in southwesterly direction.	Could connect to Lordsburg Substation, but this is 69 kV, and not optimum for 50 MW. Better to run 5-6 mile 115 kV T-Line to interconnect at Hidalgo Substation.	Lower Colorado River Basin. Surface water unknown. Moderate potential groundwater.	Private/State	Close to I-10 interchange, so good public accessibility. Cattle grazing. Simple cycle LM-6000s at power plant, but sewer plant between power plant and available area makes solar combined cycle unlikely.
4	Northeast of Deming on Hwy 26	32.437	107.537	Luna	na	7.4	Large expanses of generally flat, level land.	Vicinity of 115 kV transmission line owned by Tri-State. Old line with outdated conductors. Would require complete upgrade to support even 50 MW plant.	No surface water. Groundwater dependent on acquiring water rights.	Private/State/ BLM	From mile marker 13 to about 22 on Highway 26. Grazing land. Railroad and 115 kV transmission line. Eliminated because of transmission constraints on the 115 kV line.
5	Atop mesa west of Belen.	34.599	106.833	Valencia	39	7.3	Moderate expanses of generally flat, level land in long, 2 mile wide area atop mesa. Slopes in generally less than 1 percent. Requires moderate grubbing.	Belen Substation is at southern edge of candidate area.	Surface water unknown but unlikely. Groundwater adequate but depends on ability to get water rights.	Private	Atop mesa Reports that water availability could be a problem. If groundwater available, pumping power high. Near Alexander Municipal Airport, which could be a glint issue. Area near Belen had some haze when the team was there. Area has grazing, but vegetation tends to be scrub with little grass. Some residences in area, although typically trailer houses. Gravel road last mile or two.
6	Area west of Los Lomas, partly on Isleta Indian Reservation	34.797	106.879	Valencia	na	7.3	Moderate expanses of generally flat, level land.	Vicinity of 115 kV West Mesa to Belen transmission line.	Surface water unknown but unlikely. Groundwater adequate but depends on ability to get water rights.	Private/Indian Reservation	Grazing land. A few miles from 115 kV transmission line. This is really a continuation of northern edge of Site 5, so this has been included as part of Site 5.
7	Area along Hwy 60, leading to Sholle Pass in Manzano Mountains	34.514	106.583	Valencia	38	7.2	Large expanses of generally flat, slightly sloping land. Slopes generally 1 percent or less, although some 2 percent in upper (east) region. Slope is generally downward in westerly direction toward the Rio Grande. Minimal grubbing required.	Vicinity of 115 kV Belen-to-Willard transmission line. However, more likely to run T-Line to Tome substation.	Surface water unknown but unlikely. Groundwater adequate but depends on ability to get water rights.	Private	Grazing land. High elevation leading up to mountain pass. Along 115 kV, with railroad access.
8	Vicinity of Willard to Estancia along Hwy 41	34.647	106.140	Torrance	na	7.0	Large expanses of generally flat, level land.	Vicinity of Willard Substation or 115 kV Willard to Moriarity transmission line.	Surface water unknown but unlikely. Groundwater adequate but depends on ability to get water rights.	Private	Grazing land. Some farming. Close to 115 kV line and substation. Large area of flat land. Not near large load center. Remote from public visibility. Eliminate due to weak transmission.
9	Bluewater (Excess DOE land)	35.270623	107.947483	Cibola	1900 acres	7.0	Flat and level.	Vicinity of Bluewater Substation- Tri State.		DOE	Did not visit. Eliminated from further evaluation because of relatively low solar resource and weak transmission capability.

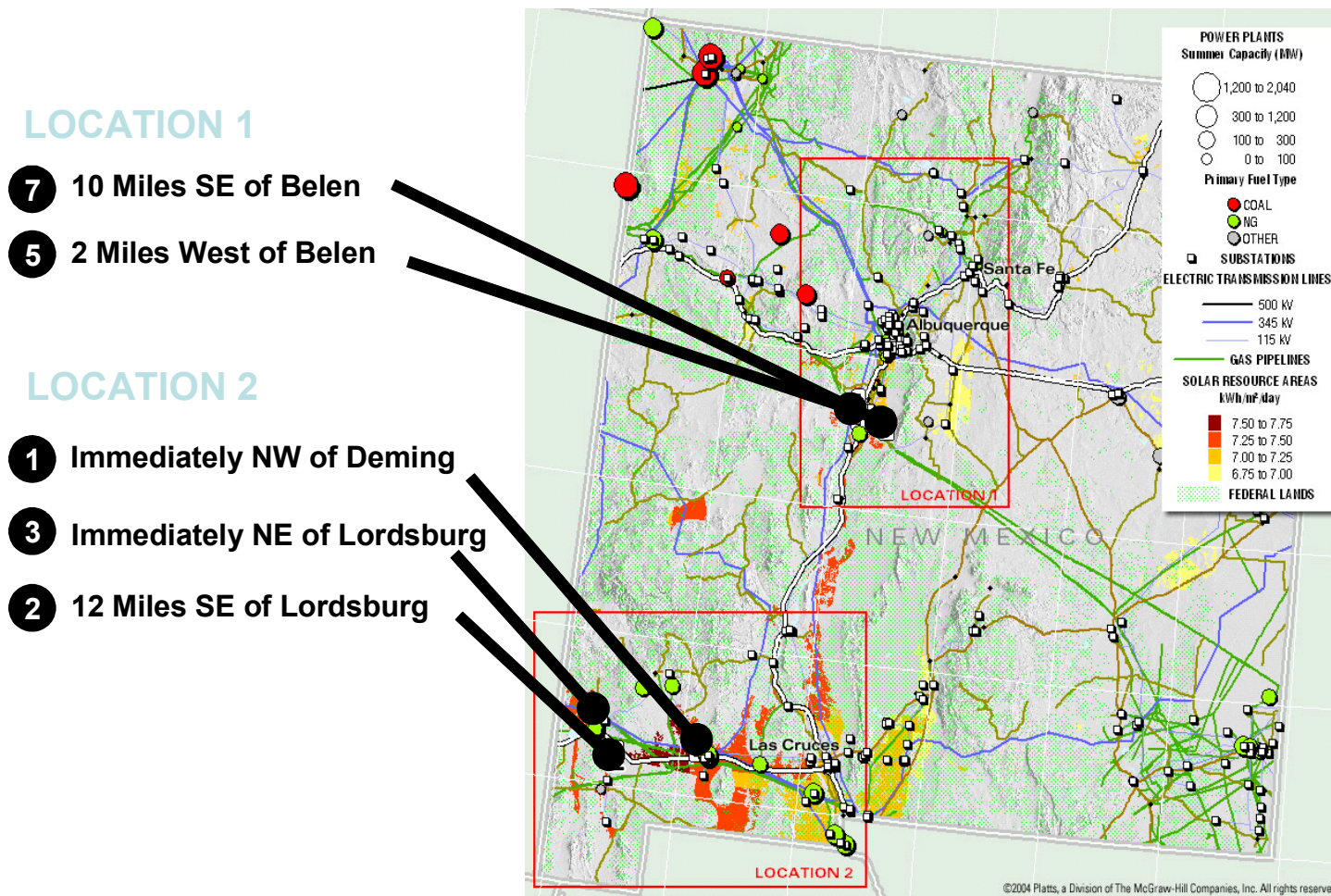


Figure 3-4
Location of Five Preferred Sites

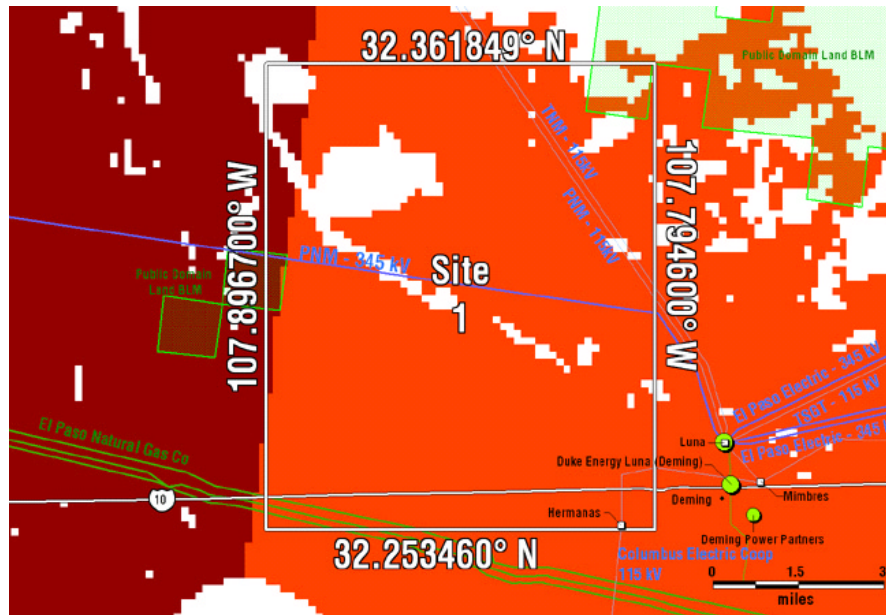


Figure 3-5
Site 1 Map

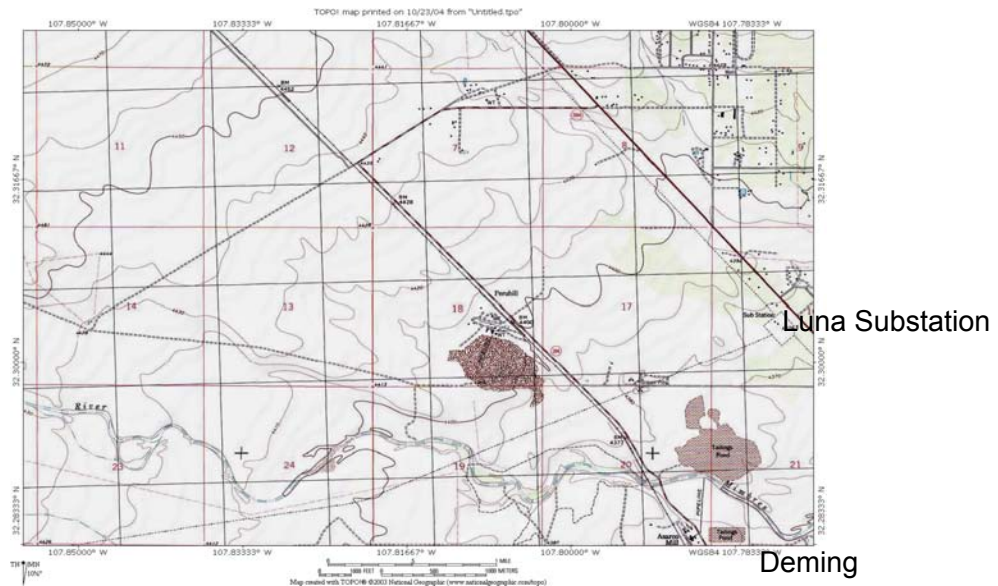


Figure 3-6
Site 1 Topographical Map
(Note: Suitable Area Extends Several Miles West)

It appears that well water could be available to meet wet cooling requirements. For the Deming Energy Facility, Duke reportedly bought 2,500 acres of agricultural land to obtain water rights. The plant will also use gray water from Deming, so that gray water would not be available for the solar plant. The cost for water acquisition for this site includes purchase of water rights, installation of a well field in the Red Mountain area, and a water pipeline from Red Mountain to the site.

Discussions with area residents (as well as roadside signs) indicated that wind storms with visibility-reducing dust storms are an issue with this site. In a brief review of available wind data for Deming, no wind levels that would damage stowed solar collectors have been identified; however, it has not been evaluated whether dust storms could damage collectors through abrasion or adversely affecting tracking mechanisms. A more detailed investigation should be performed as part of project development for this site.

3.6.2 Site 2: 12 Miles Southeast of Lordsburg

Site 2 is a 30 square mile area approximately 12 miles southeast of Lordsburg, just south of Interstate Highway 10. The area straddles the Hidalgo/Grant County line, which is coincident with Highway 113. Figure 3-7 provides the GIS rendition of this site. Figure 3-8 is a topographical map of a central area within the site region. The Pyramid Plant, shown on Figure 3-8, is a 160 MW, four-unit LM 6000 gas fired, simple cycle facility owned by Tri-State. A solar plant in this area would connect to the 115 kV substation at the Pyramid plant. Power would be transmitted to the 115 kV/345 kV Hidalgo Substation, which is a key hub for transmission in southwest New Mexico.

The solar resource for this area, based on satellite-generated data, is 7.5 kWh/m²/day, one of the better resource areas in New Mexico. It was understood through discussions with county officials from Hidalgo and Grant Counties that water is likely to be available through purchase of land with water rights. Apparently, Tri-State has purchased several hundred acres of land for water rights for the Pyramid plant.

The land area is generally flat. It appears that most of the acreage is used for grazing. The land is in the vicinity of a 30 inch El Paso natural gas pipeline. Land ownership is generally state and private. There are no known cultural, social, wetlands, or endangered species issues. The land is close to an I-10 exit, so that it would be an excellent location for a visitor's center.

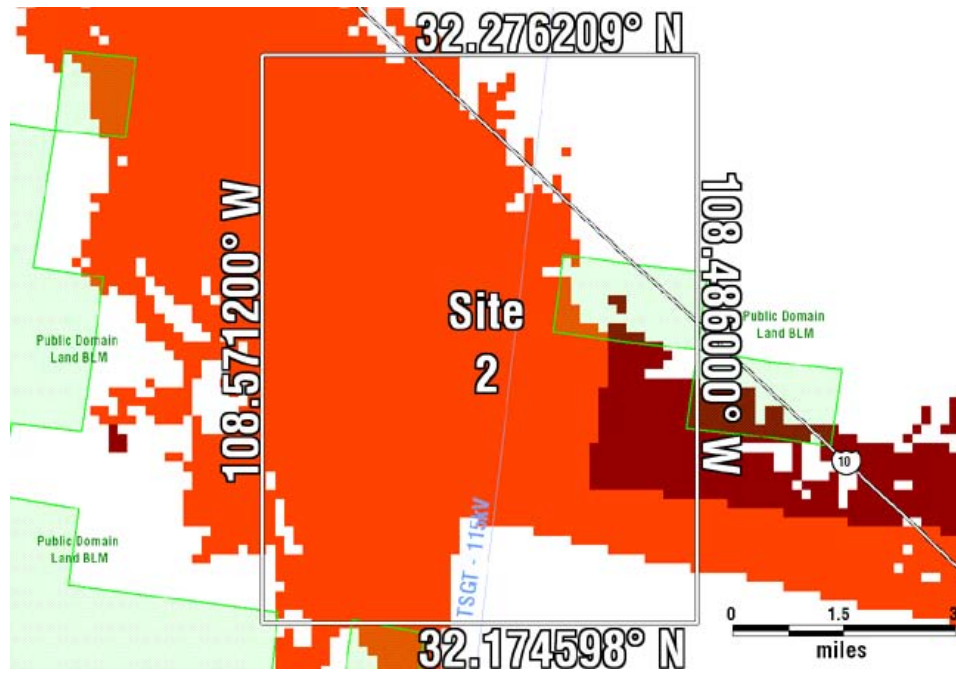


Figure 3-7
Site 2 Map



Figure 3-8
Site 2 Topographical Map

3.6.3 Site 3: Northeast of Lordsburg

Site 3 is a 6 square mile area of land in Hidalgo County, just northeast of Lordsburg. Figure 3-9 shows the GIS rendition of Site 3 and Figure 3-10 shows a topographical map of the area.

The solar resource for this area, based on satellite-generated data, is 7.5 kWh/m²/day, one of the better resource areas in New Mexico. Site 3 is near the PNM Lordsburg plant, which comprises two 40 MW LM 6000 simple cycle CTs, plus a retired steam plant. The Lordsburg plant is connected to the Hidalgo Substation through a 69 kV transmission line. It is likely that a solar plant at this site would require a dedicated 115 kV transmission line about 5 miles to the Hidalgo Substation. It is unlikely that a suitably flat site closer to the substation could be found.

Site 3 is a gently sloping land area (downward to the southwest), generally used for livestock grazing. The Lordsburg water treatment area is between the likely solar plant area and the Lordsburg plant, so that any attempt to retrofit the LM 6000s as a solar combined cycle would require a lengthy pipeline for steam or heat transfer oil.

The land is in the vicinity of several El Paso natural gas pipelines. Land ownership is generally private. There are no known cultural, social, wetlands, or endangered species issues. The land is close to an I-10 exit, so that it would be an excellent location for a visitor's center.

3.6.4 Site 5: West of Belen

Site 5 is a narrow strip of land in Valencia County, about 2.5 miles east-west by 15 miles north-south, to the west of Interstate Highway 25, and west of Belen. Figure 3-11 shows a GIS representation of the site. Figure 3-12 shows a topographical map of the southern edge of the site, near the Belen Substation. The 115 kV PNM Belen Substation is at the south end of the land area. A 115 kV transmission line from Belen Substation to the West Mesa Substation is along the east side of the land area.

The solar resource for this area, based on satellite-generated data, is 7.3 kWh/m²/day, within 5 percent of the better resource areas in New Mexico such as Sites 1, 2, and 3. The latitude differences between Sites 5 and 7 (the Central New Mexico sites), and Sites 1, 2, and 3 (the Southwest New Mexico sites), also result in a 1 to 2 percent decrease in annual energy production for the Central New Mexico sites.

Site 5 is located atop a mesa, with mildly rolling land, generally with less than a 1 percent slope. Land ownership is private, with several residences in the southern area. Siting in this area could require dealing with several landowners.

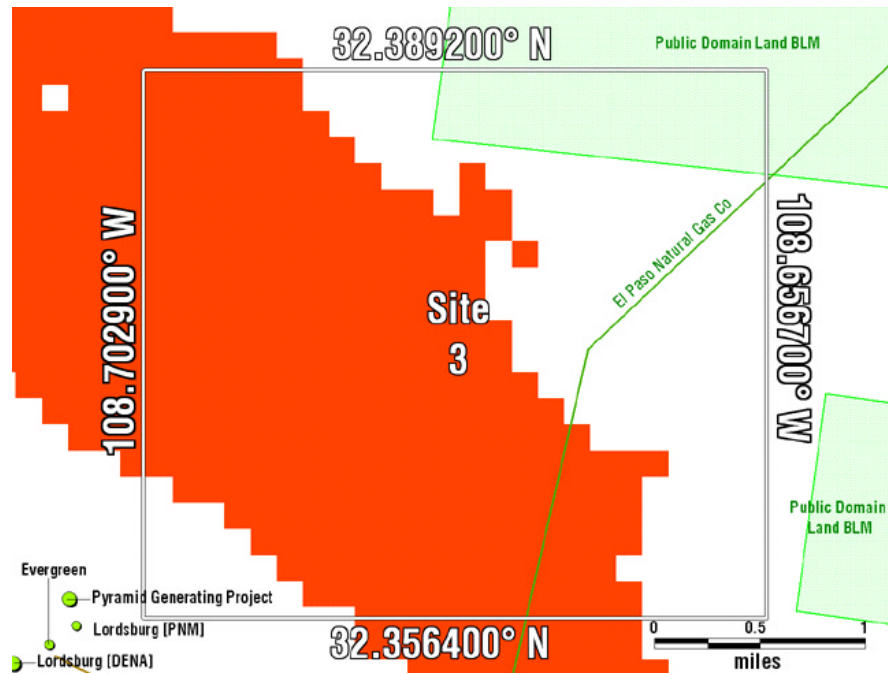


Figure 3-9
Site 3 GIS Map

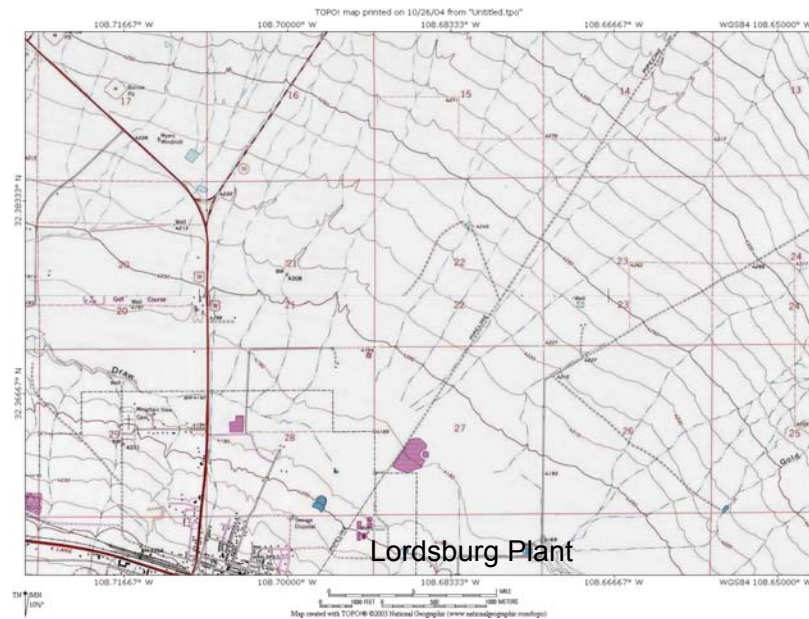


Figure 3-10
Site 3 Topographical Map

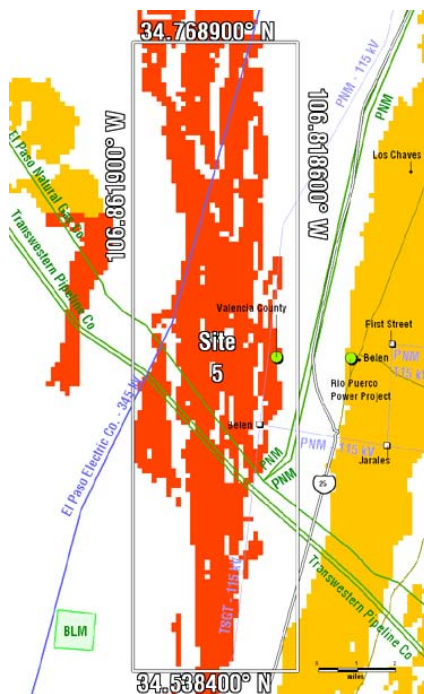


Figure 3-11
GIS Rendition of Site 5

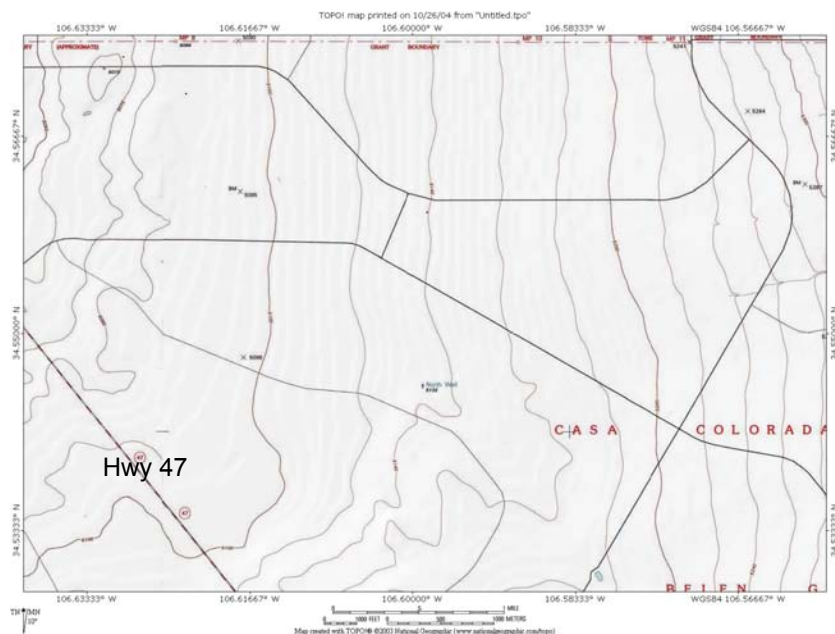


Figure 3-12
Topographical Map for a Portion of Site 5

Discussions with Valencia County officials indicated that water quality and quantity is likely to be an issue at this site. This could necessitate dry cooling for a plant at the site. Furthermore, there was considerable public opposition during recent permitting of a 280 MW Peoples Energy gas fired simple cycle plant just southeast of Belen.

The site is near I-25, so that access to a visitor's center would be reasonably easy.

3.6.5 Site 7: Southeast of Belen

Site 7 is a 38 square mile area of land in Valencia County along Highway 47, about 10 miles southeast of Belen. The solar resource for this area, based on satellite-generated data, is approximately 7.2 kWh/m²/day, about 5 percent less than the resource for Sites 1, 2, and 3. The area is a geographical bench on the slope from the Rio Grande up to the Manzano Mountains on the east. The land has a slope of about 1 percent in the bench area. Figure 3-13 provides a GIS representation of the area. Figure 3-14 shows a topographical map of the southern edge of the site, near the Belen Substation. The 115 kV PNM Tomes Substation is several miles northwest of the land area. A 115 kV transmission line from the Tomes Substation to the Willard Substation runs along the southern edge of the land area. However, PNM states that this transmission line is constrained, so that the likely interconnection for a plant at this site would be a dedicated 115 kV transmission line to the Tomes Substation. Depending on the exact location of the plant, this could require a 12 mile transmission line.

Site 7 would have issues similar to those for Site 5, which is just a few miles west of Site 7. Acquiring sufficient water for wet cooling could be difficult, possibly necessitating the use of dry cooling. Similar to Site 5, the public opposition that surfaced during the recent permitting of a 280 MW Peoples Energy gas-fired simple cycle plant just southeast of Belen could be an issue, although an environmentally friendly solar plant may not encounter the same resistance.

The site is somewhat more remote from I-25 than Site 5, making access to a visitor's center a little more difficult.

3.7 General Permitting Requirements

A solar plant would be subject to various federal, state, and local permitting requirements. It is not anticipated that any of these requirements would provide a road-block to the construction of a solar power plant in New Mexico, but development would require appropriate, timely submittals. Appendix A provides a table of the likely permits required for the plant. Local permit requirements are addressed in a general fashion, listing typical permits. Development would require the identification of permitting requirements for the specific local agencies pertinent to the sites.

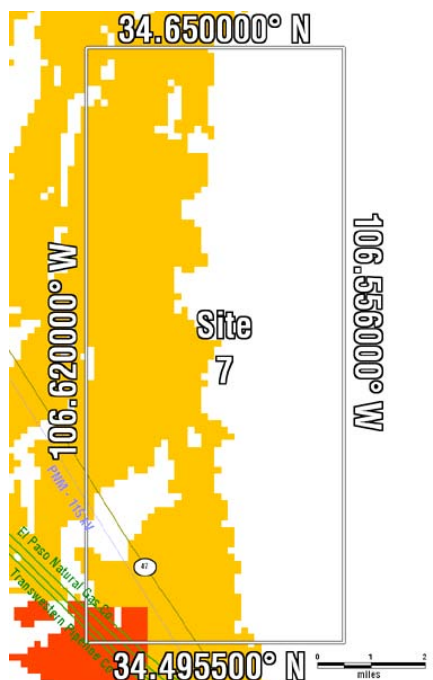


Figure 3-13
GIS Rendition of Site 7

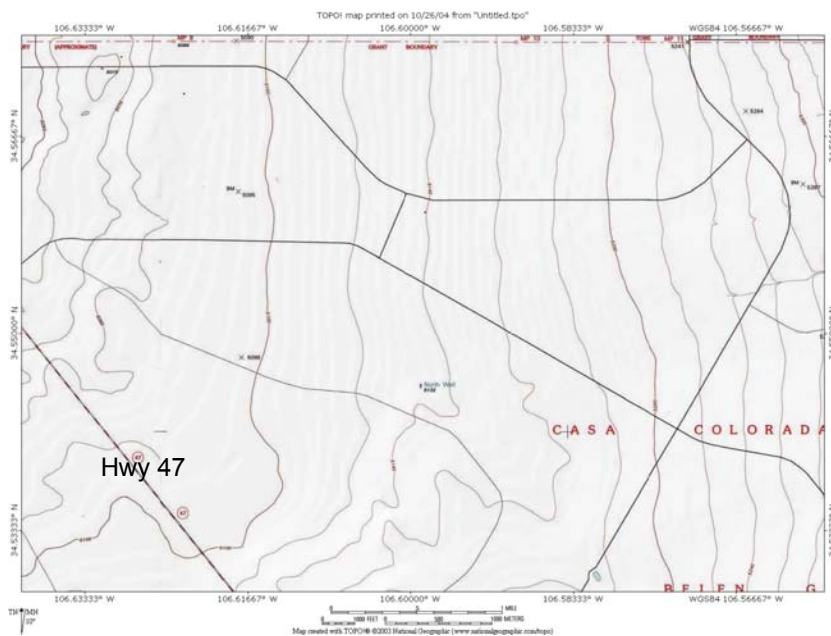


Figure 3-14
Topographical Map for a Portion of Site 7

3.8 Endangered Species and Cultural Resources

3.8.1 Endangered Species

The potential presence of protected species of animals and plants was considered for the five sites in New Mexico. This consideration included the following listings:

- Endangered Species Act (ESA) items listed as *threatened* or *endangered*.
- State of New Mexico items listed as *threatened* or *endangered*.
- BLM items listed as *special status*.
- US Forest Service (USFS) items listed as *sensitive*.

The state of New Mexico and the New Mexico Natural Heritage Program list additional species in these areas, but those species have no legal protection.

Since the precise location of the proposed facilities is not known, and no site visits have been made to ascertain existing environmental conditions, the comments provided here are considered provisional and should be more thoroughly investigated in the future.

For this evaluation, the team identified the protected species of concern as being those listed under the ESA (regulated by the US Fish and Wildlife Service [USFWS]) and the state of New Mexico. These listings are considered according to each site in the following paragraphs.

Site 1: Deming, New Mexico

This site has an overall low potential for the occurrence of protected species, primarily due to prior development at the site. Protected animals would presumably avoid the site, and site development would have disturbed the historic habitat to the point that unusual vegetation, including protected plants, would have been eliminated from the area.

Protected species in the area appear to include three species, two plants and one bird. The two plants are New Mexico-listed endangered species. One is distributed along the Mexican border to the south and should be of no concern to the project. The second is Night-blooming Cereus (*Peniocereus greggii* var. *greggii*), a cactus, and should warrant site investigations because this species does withstand disturbance to some degree, and numerous records exist for the area. The Mexican spotted owl is reported in the region, but should not be of concern near the project site.

Site 2: Lisbon, New Mexico (Hildago/Grant Counties, 12 miles southeast of Lordsburg)

The existing plant area has the potential for protected species that are similar to those for Site 1, although perhaps slightly more so due to the more remote location of the

site. A third plant listed as endangered by New Mexico, Parish's alkali grass (*Puccinellia parishii*), potentially occurs in the area and, due to its habitat preference, could occur in the immediate project area.

Site 3: Lordsburg, New Mexico (Hildago County, approximately 1 mile NE of Lordsburg)

The existing plant site has protected species concerns similar to those of Site 2.

Site 5: Belen, New Mexico (Valencia County, west of Belen on mesa)

This is an undeveloped site (i.e., no generation plant) atop a mesa. In Valencia County, only three species are listed with meaningful regulatory status: puzzle sunflower (ESA threatened; New Mexico endangered); Rio Grande silvery minnow (ESA threatened; New Mexico endangered); and southwestern will flycatcher (ESA threatened; New Mexico endangered). No habitat exists for the minnow. The sunflower occurs around wetlands that are presumably not present atop the mesa, so there would appear to be no potential for occurrence. The flycatcher could be in the region, and this situation should be investigated.

Site 7: Becker, New Mexico (Valencia County, 10 to 15 miles SE Belen)

This is an undeveloped site (i.e., no generation plant). The area appears to be somewhat disturbed by residential development, but no maze of roadways was observed on aerial photographs. In Valencia County, only three species are listed with meaningful regulatory status: puzzle sunflower (ESA threatened; New Mexico endangered); Rio Grande silvery minnow (ESA threatened; New Mexico endangered); and southwestern will flycatcher (ESA threatened; New Mexico endangered). No habitat exists for the minnow. The sunflower occurs around wetlands, so unless wetlands are present, there is little or no potential for occurrence. The flycatcher could be in the region, and this situation should be investigated.

3.8.2 Summary

It does not appear that protected species (federal or state) should be a significant concern at any of the sites. Despite these preliminary findings, it is advised that as project development moves forward, a site walk-over be conducted by a qualified biologist (i.e., a botanist familiar with southwestern vegetation) to determine the nature of the exiting plant communities and wildlife habitat on the site and in the immediate vicinity. This could be done during any season, providing there is no snow on the ground.

3.8.3 Cultural Resources

A search for cultural properties in or around the Southwest and Central Locations was performed using the New Mexico Historic Preservation Division Web site. No properties were identified that would eliminate the sites from consideration. If a specific site were being developed, it would be necessary to do a more detailed search.

3.9 Site-Related Costs

Preliminary site-related cost estimates were developed for the Central Location (Sites 5 and 7) and the Southwest Location (Sites 1 and 2), which are considered in the economic analysis. The base cost estimates for the systems include certain site-related costs. The following are costs that are site-specific and could affect decisions between sites.

Transmission cost estimates were based on rough cost estimates from PNM for the following 115 kV and 345 kV transmission lines and system upgrades:

- 115 kV transmission line--\$150,000 to \$200,000/mile.
- 345 kV transmission line--\$750,000 to \$1,000,000/mile.
- Interconnect to existing 115 kV transmission line--\$2,500,000.
- Interconnect to existing 345 kV transmission line--\$7,000,000.
- Connection to existing 115 kV substation--\$750,000.

Site preparation costs include clearing and grubbing, and grading into terraces to provide relatively flat blocks of land within the plant boundaries. Earth moving was estimated to cost \$6/cubic yard; clearing and grubbing were estimated to cost \$600/acre.

Water acquisition costs are extremely site-related. Valid estimates require a far greater level of detail for site development than can be covered in the scope of this project. For the Southwest Location, data for water use at the Deming Energy Facility was scaled as provided in a white paper prepared for the New Mexico Water and Natural Resource Interim Committee in September 2001. That paper included case studies for wet and dry cooling at the Deming Energy Facility (called the Luna Plant in that study). The team used similar water costs for the Central Location, with the understanding that the Central Location was more likely to have water restrictions that could mandate the use of dry cooling.

Natural gas interconnection costs were estimated to be \$120,000 plus \$1.4 million per mile. Distances to natural gas pipelines were determined by using Web-based databases to a nominal latitude/longitude point within each site area.

3.10 Siting Recommendation

Of the five preferred sites identified by the team, the recommended solar plant locations were identified as Sites 1, 2, and 7. The Southwest Location (Sites 1 and 2) provides superior solar resource and probably has easier land and water acquisition considerations than the Central Location (represented by Site 7). However, the Central Location has better access to the Albuquerque load center. Sites 1 and 2 were chosen as preferred sites in the Southwest Locations rather than Site 3 because Site 3 is a smaller, more constrained area, with slightly greater land slope. Also, Sites 1 and 2 would likely require a shorter connecting transmission line. Site 7 was chosen as the preferred site in the Central Location rather than Site 5 because Site 7 is less developed and is not in the vicinity of an airport.

In further analyses, the team considered the locations to be represented as a Central Location and a Southwest Location. The subsequent plant performance and financial analyses are considered to be appropriate for the two locations, with key differences resulting from solar resource and latitude-related solar efficiency effects. The primary considerations include the identification of the power market and the ability to get electricity to the market. These items are discussed in Section 4.0.

4.0 Federal and State Programs

The purpose of this task was to assess the extent to which federal and state programs, requirements, and incentives could be utilized to enhance the viability of a CSP project in New Mexico. The analytic approach used consisted of the four steps illustrated on Figure 4-1. The first step was to catalogue and report existing federal and state incentives. Then, a list of proposed and historical federal and state incentives was prepared. This entire set was then characterized in terms of the expected impact on the cost, performance, and financial characteristics of a proposed CSP project in New Mexico. The last step was to estimate the CSP COE for each policy in order to estimate its effectiveness. Please note that the COE presented in this section is provided only to show the impact of various incentives. Section 8.0 presents rigorously calculated COE values.

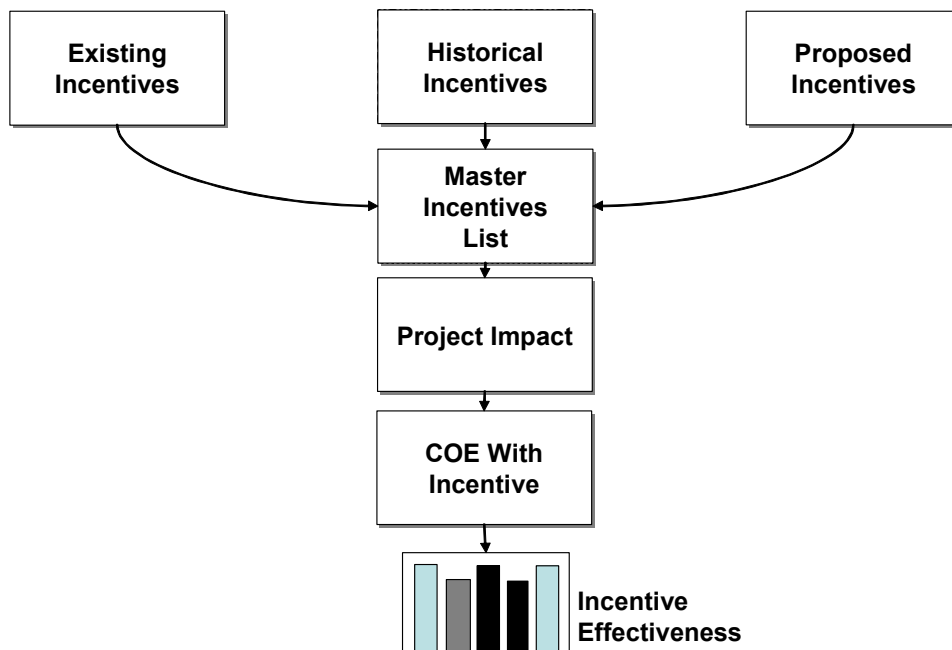


Figure 4-1
Analytic Approach

A CSP project, or any power project for that matter, involves many participants, each with different roles, as illustrated on Figure 4-2. The project sponsor is the entity or group of entities interested in the development of the project, and which will benefit economically or otherwise from the overall development, construction, and operation of the project. The project company is the entity that will own, develop, construct, operate,

and maintain the project. The precise nature of the organization for this entity is dependent upon myriad factors. Lenders, including banks, insurance companies, credit corporations, and other lenders, provide debt financing for projects. Lenders can either provide short-term construction financing or longer-term permanent financing. The output purchaser, often called the “offtaker,” is the purchaser of all or some of the products or services produced at the project. The contractor is the entity responsible for construction of the project; it bears the primary responsibility in most projects for the containment of construction-period costs. The operator is the entity responsible for the operation, maintenance, and repair of the project. With some projects, this role is filled by one of the owners of the project company. In other projects, the operator role is undertaken by a third party under an operating agreement. The government is the governing authority at the local, state, and federal levels in which the project is located. As such, the government is typically involved as an issuer of permits, licenses, authorizations, and concessions. Governments may also provide incentives.

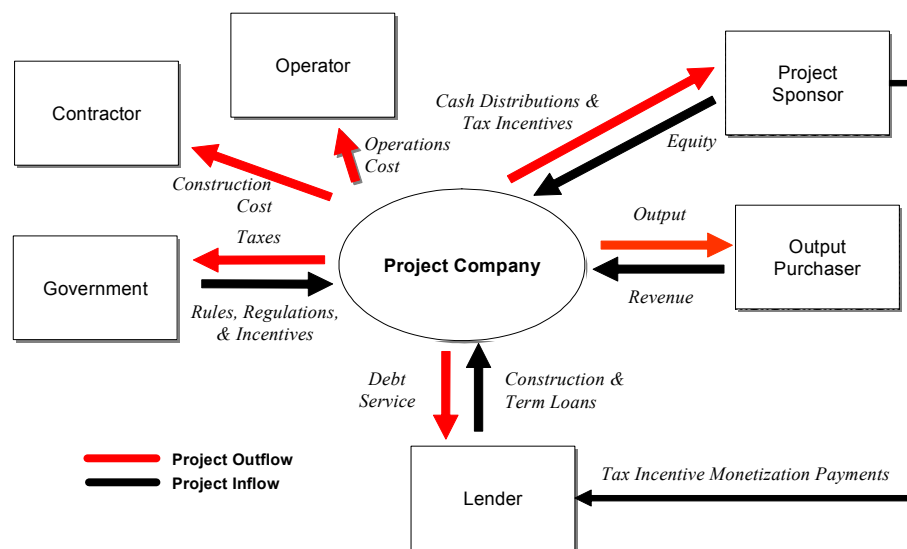


Figure 4-2
Basic Power Project Structure

Figure 4-2 also shows the major cash flows for the project. The revenue stream is generated by the purchaser of the plant’s energy output. This revenue is then used to pay the costs incurred by the plant operator and others, to service the debt via payments to the lenders, and to pay taxes to the various governmental agencies. What is left is the after-tax cash flow, which goes to the project sponsors. Figure 4-3 summarizes the cash flow for the project.

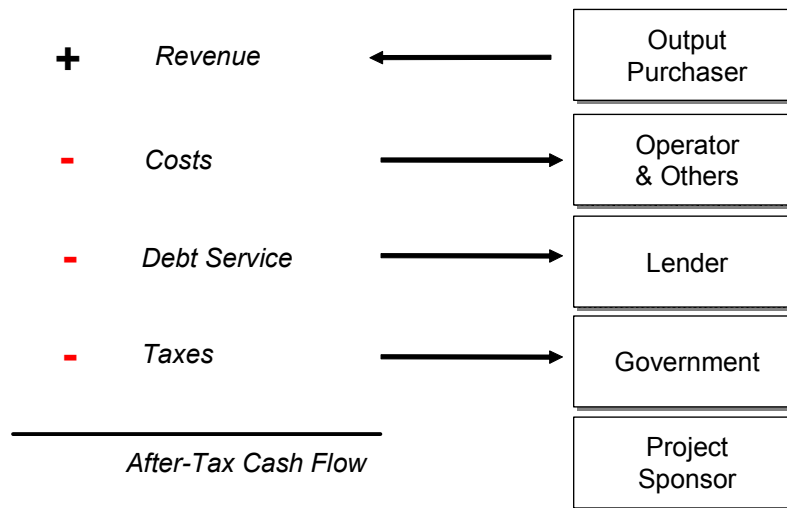


Figure 4-3
Cash Flow Fundamentals

These cash flows are embodied in a pro forma that is used to estimate the COE. The COE is the minimum revenue per unit of output necessary to meet debt coverage requirements, provide an acceptable rate of return to the owner(s), and cover the taxes and O&M costs. Obviously, a lower COE is preferred. The debt coverage requirement is the ratio of the available cash to the debt payment, which is computed monthly. The pro forma analysis was performed for the following set of assumptions, called the Base Case:

1. Given its commercial history and the availability of accurate cost and performance estimates, parabolic trough was used as the base case technology in this analysis.
2. A nonrecourse debt project financing structure was employed. Non-recourse means that the project is a limited liability corporation holding the credit agreements. The project is the sole collateral for the lenders; i.e., the lenders do not have recourse to the project corporation owners (such as a holding company). Tax benefits are assumed to be fully valued via a production tax credit (PTC) agreement that specifies this value and/or due to the absence of tax appetite limitations as a result of credit transferability.
3. A limited liability partnership is the underlying ownership structure for this base case analysis. This arrangement is the most common structure used in wind energy financing today and one of the likely approaches for a large-scale solar project.

4. All results are preliminary. Ultimate values will be a function of technology cost and performance, ownership structure, financial structure, and incentive structure.

Incentives can be used to enhance revenue, reduce costs, reduce the debt service, or reduce the required tax payments. The goal is to increase the after-tax cash flow. Effects of various incentives on COE are shown on Figure 4-4 for a 50 MW trough plant with 6 hours storage, located in southwestern New Mexico.

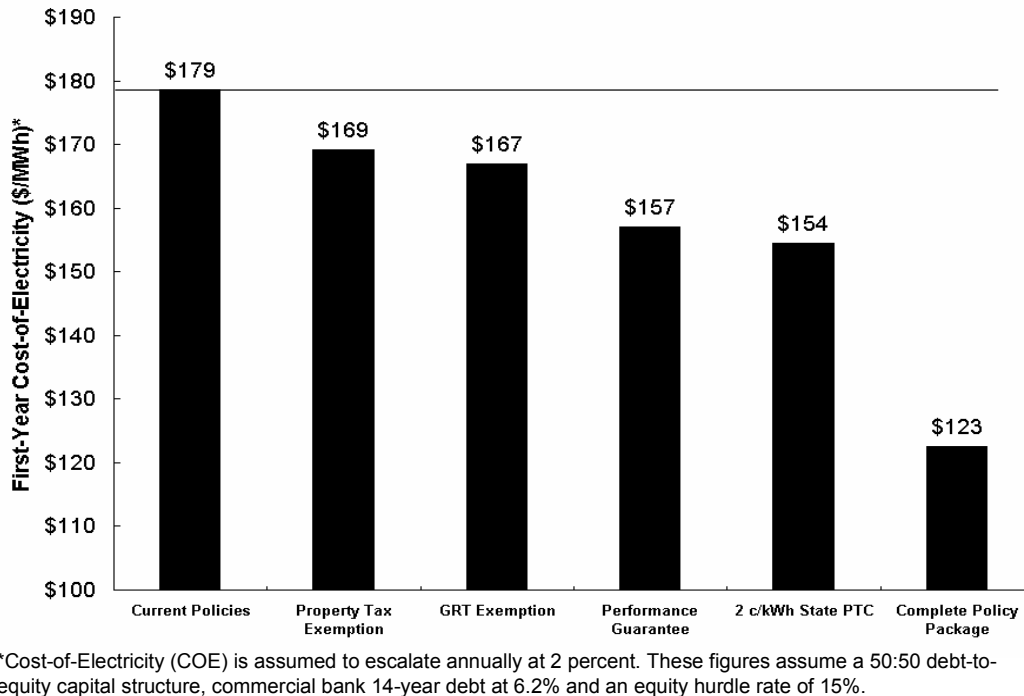


Figure 4-4
Effects of Incentives for 50 MW Southwest Plant

4.1 Revenue Enhancing Incentives

There are three ways that incentives can enhance revenue. The first is an above-market, long-term power purchase agreement (PPA). A PPA is required for project financing. An above-market PPA price serves as a mechanism to transfer part or all of the above-market COE for CSP to the offtaker. Obviously, an above-market PPA requires some mechanism for the off-taker to recover its cost. A second incentive involves capacity payments and variants of such payments. Capacity payments are not separate from the PPA; they are a part of the PPA. Capacity payments are commonly provided to conventional generation projects for providing energy when needed. Dispatchable solar plants should be eligible for the same payments. Finally, production payments and

variants can be used. Production payments are similar to PTCs, which focus incentives on production rather than construction, but provide a direct cash payment in lieu of a tax credit.

Revenue-enhancing incentives are attractive from the project sponsor's (owner's) perspective, because they are more liquid than tax incentives, which sometimes cannot be used due to tax appetite limitations and/or must be secured by a credit-worthy sponsor. Production payments are more favorable from the government's perspective, because they provide incentives for production, rather than construction, thereby reducing the risk of "gold-plated" construction and poor performance. For CSP projects, the PPA should be structured to include all of the benefits of solar power, including energy, capacity, and renewable energy credits (RECs).

4.2 Cost Reduction Incentives

There are three incentives that will reduce costs. The first category comprises construction grants or rebates. Construction rebate type incentives are similar to Investment Tax Credits (ITCs), but provide "cash back" for project construction rather than providing a tax write-off. The second category comprises government-sponsored reserve accounts in which the required reserve accounts for O&M, debt service, and major maintenance are formed to mitigate project risks. The cost of the debt service reserve account alone can approach \$10 million for a 100 MW CSP project. The third category involves incentives such as land grants and insurance, in which a variety of direct costs could be covered by the government to reduce project expenses. For example, land royalty expenses could be eliminated through a state land grant. The government could also pay for other costs, such as construction insurance.

Cost reduction incentives are attractive from the project sponsor's perspective, because they reduce up-front and/or direct out-of-pocket expenses. Direct cost reduction incentives have a limited ability to reduce the cost of energy from CSP projects, because these costs typically make up a small share of the cost of production from CSP facilities. Similar to revenue-enhancing incentives, cost reduction incentives may be viewed as "hand outs" that do not provide the proper incentives to project participants. Other ways to reduce costs, including risk transference measures, will be discussed later.

4.3 Debt Service Reduction Incentives

There are two kinds of incentives to reduce debt service costs. The first type extends the term of the debt, while the second type reduces the interest rate. Longer debt repayment periods mean lower debt service obligations and higher after-tax cash flow. The government can provide direct long-term financing for CSP projects and/or provide

the necessary incentives to induce commercial lenders to provide extended tenors, such as full or partial loan guarantees. Lower interest rates mean lower debt service obligations and higher after-tax cash flow. The government can provide low interest financing, such as tax-exempt bonds, or can provide the necessary incentives to lower commercial loan interest rates, such as paying the margin. Because of the high capital costs of CSP projects and the high debt service obligations, incentives and programs designed to increase terms and/or reduce interest rates can be very effective at improving CSP project competitiveness.

4.4 Tax Reduction Incentives

The major tax reduction incentives are the PTC and the ITC. Federal and/or state PTCs provide a tax credit per kWh of electricity generated for a specific number of years. The Federal Solar PTC is 1.8 cents/kWh for 5 years. The New Mexico PTC is 1.0 cent/kWh for 10 years, subject to annual payments and generation limits. ITCs provide project sponsors with a tax credit for initial development costs. The Federal Solar ITC provides a credit for 10 percent of depreciable costs. Projects owners can take the Federal PTC or ITC, but not both. Employment tax credits are also sometimes used to provide incentives for projects that will stimulate economic development. Other taxes can be reduced or eliminated to provide incentives for solar project development. California has a solar property tax exemption; some states provide a sales tax exemption for solar equipment.

Tax reduction incentives can be very effective for improving the cost competitiveness of CSP projects. A variety of tax incentives are currently used at the state and federal level to induce investment in alternative energy generation technologies. The effectiveness of tax incentives is often limited by “tax appetite” limitations. These limitations can be avoided if tax incentives are transferable or refundable. Tax incentives must also be constructed to avoid unfavorable interactions. Alternative financing structures are often developed to maximize tax benefits. Such structures include equity “flip” arrangements and sale/lease-back structures.

4.5 Risk Transfer Mechanisms

There are cost implications regarding project risk. The three major project risks are construction cost delays or cost overruns, operational cost overruns, and the inability to service the debt due to underperformance or poor solar resources. The contractor bears the construction-related risks and usually monetizes that risk by adding a premium (sometimes as much as 20 to 30 percent) to the construction cost. This risk can be managed with a performance guarantee or bond. The operator bears the operations-related risks and usually monetizes that risk the same way, with a 20 to 30 percent

premium payment. Tools that the owner can use include an operating reserve fund or warranty bonds. The lender bears the underperformance-related risks and monetizes that risk by offering higher interest rates or shorter terms. If the performance risk is perceived to be high, the loan may be denied altogether. A full or partial loan guarantee can mitigate this risk.

There are several ways for the government to transfer performance risk to reduce construction cost premiums, including full or partial performance guarantees, early construction bonuses, insurance, and reserve funds. There are also several ways for the government to transfer operations risk to reduce operations cost premiums, including full or partial operations cost guarantees, operations cost reduction incentives, insurance, and reserve funds. Governments often transfer commercial loan default risk by issuing full or partial loan guarantees, or by directly serving as a source of debt funds. Such programs have been used by the steel and airline industries. These programs are typically used in new technology projects and ailing, but economically essential, industries.

In the context of project financing structures, the costs of risks are internalized by parties that bear them through premiums, bonuses, and increased margins. By accepting partial or full project risks, the government can reduce project costs. Risk transference measures have been used with mixed success. While government acceptance of risk can reduce project cost, it can also have a negative effect by reducing or even eliminating the economic incentives which ensure that project parties perform work in such a way so as to ensure project success. In addition, the government is typically unfamiliar with project risks and, therefore, unsuited to manage these risks. A risk transference measure may have a limited role in the context of a CSP project if the measure is well constructed and government liability is limited. For example, partial performance operations and loan guarantees have the potential to enhance CSP project cost competitiveness, while limiting government liability.

4.6 Conclusions

The most direct way to provide incentives for a CSP project is to develop a PPA that provides sufficient revenue to cover costs, service debt, pay taxes, and provide an acceptable rate of return to project sponsors. Because of the high capital costs of CSP projects, incentives and programs designed to increase debt tenors and/or reduce debt interest rates can reduce CSP project costs significantly. Tax incentives can also be very effective for improving the cost competitiveness of CSP projects. However, the effectiveness of tax incentives can be limited by “tax appetite” limitations, unless incentives are transferable or refundable and do not interact unfavorably. Risk transference measures have been used with mixed success. By accepting project risks,

the government reduces or eliminates economic incentives for project parties to ensure project success. Risk transference measures may have a limited role in CSP project financing if such measures are well constructed and government liability is limited.

5.0 Market Assessment

The objective of this task was to provide an assessment of the revenue potential for a CSP plant located in New Mexico, selling energy, capacity, and environmental attributes in both in-state and out-of-state markets.

5.1 Transmission Paths

Figures 5-1 and 5-2 show the transmission access from Locations 1 and 2 to the major markets in the southwestern United States. From the sites just south of Albuquerque (Location 1), power could be provided to the relatively large Albuquerque load area. As indicated on Figure 5-1, power could be delivered to the El Paso control area at the West Mesa 345 kV Substation and then delivered south on El Paso's West Mesa-Arroyo 345 kV line. This transfer would involve a change that could adversely affect the transfer capacity of northern New Mexico. From Location 1, power could also be sent to the Four Corners area and from there onward. Deliveries from the Four Corners area to the Front Range area could expect to have limitations for long-term transactions, due to the west-to-east transmission constraint in central Colorado. Transmission delivery west from the Four Corners area to Arizona, California, and Nevada is also problematic. There is little or no long-term (1 year or longer) firm transmission service available to the west. Shorter-term transmission service is available to accommodate a 50 MW transaction.

Moving power from the sites in the southwestern corner of New Mexico (Location 2), as indicated on Figure 5-2, is problematic. Transmission capacity north to central and northern New Mexico is probably unavailable. Moving the power east is also difficult. Significant constraints occur in the 345/115 kV transformation into Las Cruces. Therefore, it is unlikely that the power could be sold using this path, unless this power is used in lieu of other imports. Power could be moved west via TEP, which offers 113 MW to 337 MW of long-term firm transmission service to the TEP load center. TEP is also offering 158 MW of firm transmission service from Greenlee to Phoenix for a portion of 2005, and all of 2006 and 2007. While capacity is available north into the Four Corners area, transmission delivered west and east into Colorado is problematic, as previously discussed. Delivery to southern California would be possible by arranging delivery through a single transmission provider that bridges the gap between the New Mexico and Palo Verde switchyard, where transactions with southern California entities could be made.

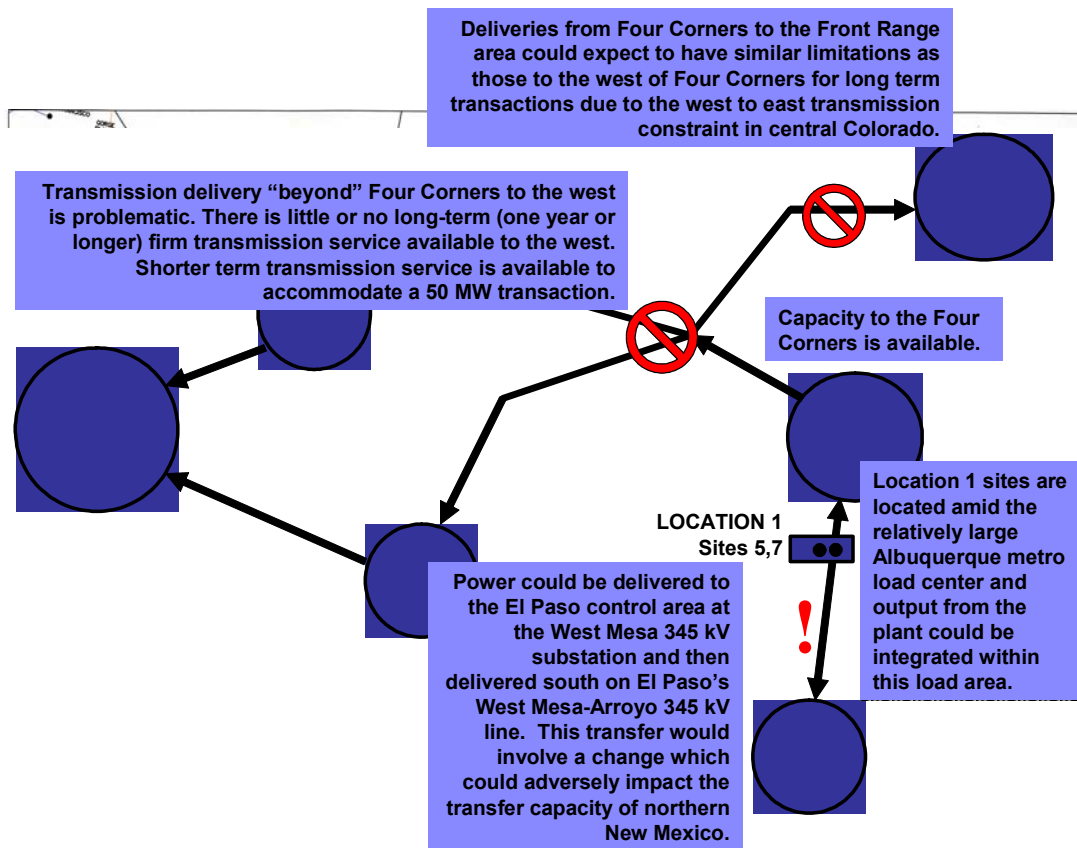


Figure 5-1
Market Access for Location 1 Plant

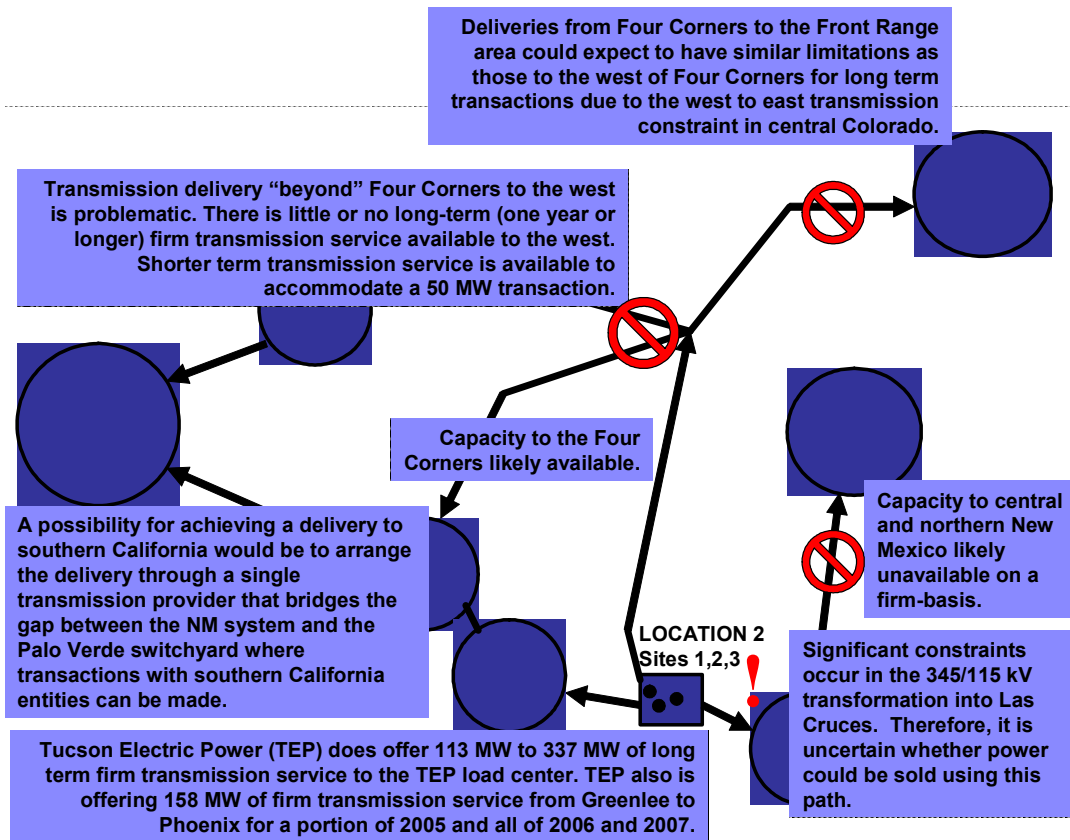


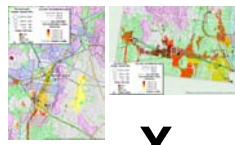
Figure 5-2
Market Access for Location 2 Plant

5.2 Energy Revenue Forecasts

Using the energy prices for Arizona, California, Colorado, New Mexico, and southern Nevada, energy revenue can be estimated for the two locations and the six technology configurations. The methodology used is illustrated on Figure 5-3. The result, a set of 60 average annual revenues, is presented on Figure 5-4. California is the highest revenue market for CSP power generated at either location and with any technology configuration. The configurations with 6 hours' thermal energy storage offers the highest revenue potential. Three hours' storage offers increased revenue potential relative to stand-alone solar. The revenue potential of Location 1 is less favorable than Location 2, and stand-alone solar, dry cooling, and hybrid each have comparable revenue potentials.

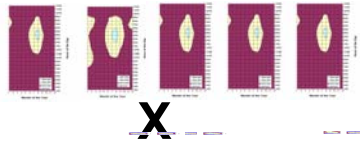
Therefore, a 50 MW CSP plant with 6 hours' storage located in the southwestern area of New Mexico and selling its output to California would have the greatest average annual revenue potential, predicted to be about \$7 million. This should be compared to the capital cost of a 50 MW CSP plant with 6 hours' storage, which is about \$260 million.

Emerging voluntary and compliance REC markets throughout the western United States have the potential to provide an additional revenue source for the non-energy attributes of solar plant output. However, these markets are not yet well defined and are generally illiquid. As a result, it is unlikely that REC revenue could be used to attract financing. The Center for Resource Solutions investigated REC markets in New Mexico and the Southwest as part of this study. Appendices B and C report their findings.



2 Locations

Southwest New Mexico, Central New Mexico.



5 Energy Markets

New Mexico, Arizona, California, Colorado, Southern Nevada.

6 Technology Configurations

50 MW Trough, 50 MW Trough Hybrid, 50 MW Trough 3H Storage, 50 MW Trough 6H Storage, 100 MW Trough.

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60 Energy Revenue Forecasts

Figure 5-3
Energy Revenue Forecast Methodology

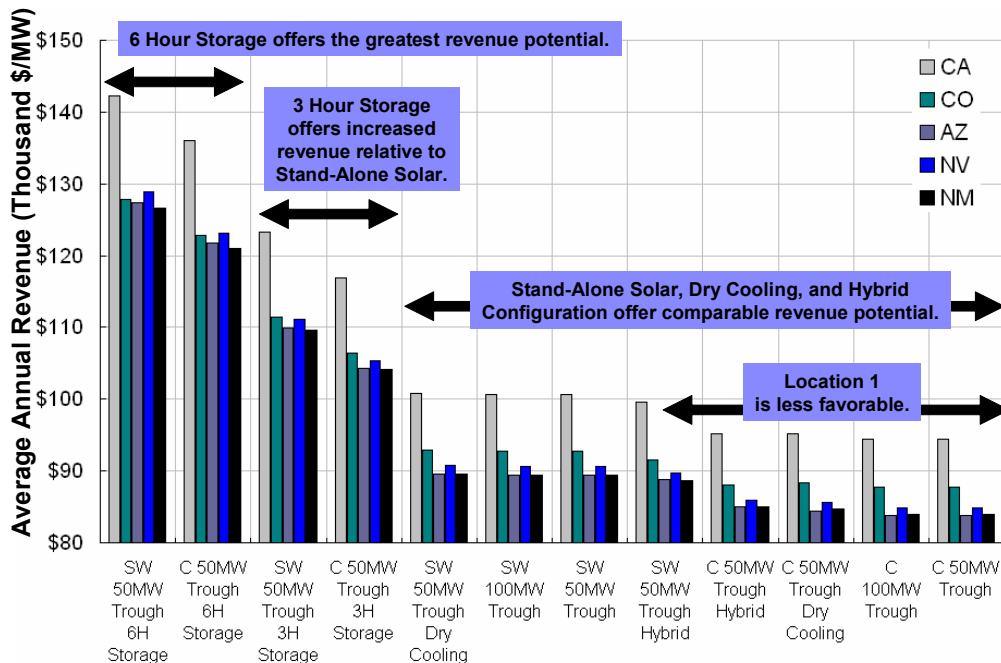


Figure 5-4
Energy Revenue Forecast Results by State

6.0 Financing Assessment

The objective of this task was to evaluate alternative project development approaches and determine how they impact the cost and level of risk associated with a CSP plant located in New Mexico.

Three development approaches were investigated:

- Utility Purchase.
- Private Ownership.
- Public-Private Partnership.

6.1 Utility Purchase

In the Utility Purchase option, the project would be developed by a private sector developer and then sold to a single utility or consortium of utilities. The utility might provide construction financing and purchase the project from the developer. The purchase commitment from the utility would provide the “take out” needed to obtain construction financing from commercial sources. The developer would earn a development fee and would be reimbursed for development costs. Figure 6-1 shows the two steps associated with this approach; the first step is the building of the plant and the second is the utility purchase. Advantages of this approach include the following:

- It is relatively simple and straightforward.
- It reduces or eliminates the need for public sector financing.
- CSP plants are “integrated” into the generation/transmission infrastructure.
- The cost for solar energy is rolled into the rate base.

Disadvantages to this approach include the following:

- Electric utilities may not favor solar power.
- Finding a utility willing to buy and operate the plant might be difficult.
- There might be issues with how the utility finances the purchase of the CSP plant.
- There might be a risk of protracted negotiation over terms and conditions of sale.

6.2 Private Ownership

In this approach, the project would be developed by a private sector developer who funds the development cost. The project would be financed with a combination of equity and debt. Debt could be sourced from a commercial bank, from issuance of a taxable bond, from issuance of a tax-exempt bond, or with a loan from a development

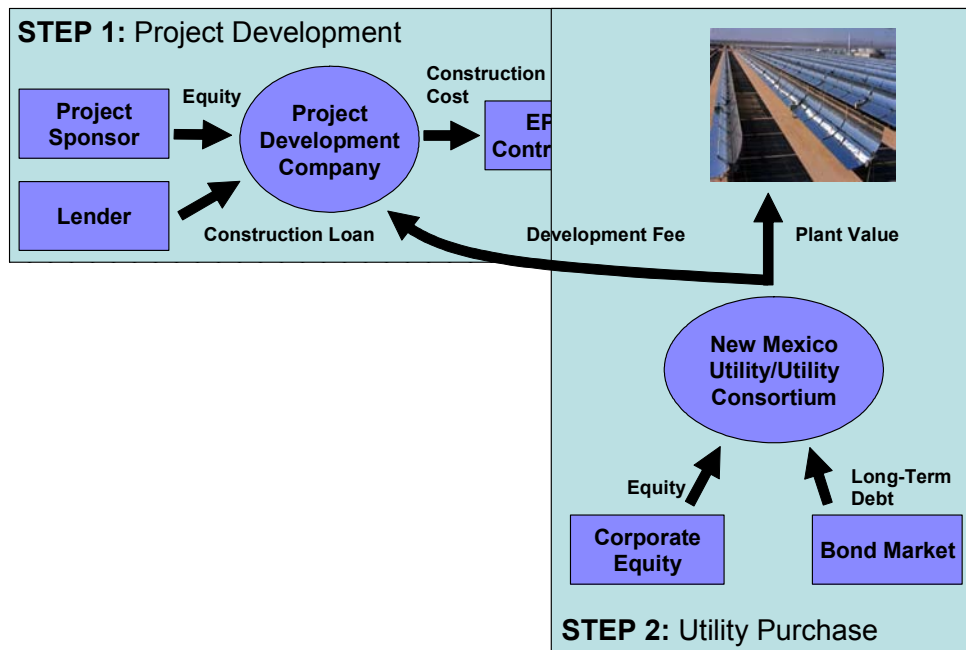


Figure 6-1
Development Approaches: Utility Purchase

bank. The equity would be raised from private sector investors who have a use for tax credits and for the accelerated depreciation available from the project. Figure 6-2 shows the interrelationships between the key entities and the various cash flows. Advantages of this approach include the following:

- There is strong interest by CSP developers.
- A competitive bid may produce the best candidate.
- Private sector ownership may be more politically feasible than the public sector option.
- Infrastructure is developed for additional plants (for example, to meet the Western Governors' Association 1,000 MW goal).

Disadvantages to this approach include the following:

- Most CSP development companies have weak balance sheets.
- This approach requires alliance between developer; engineering, procurement, and construction (EPC) contractors; lenders; and equity investors.
- An acceptable power PPA needs to be negotiated with the electric utility.
- The higher PPA price has to be justified to the public and ratepayers.

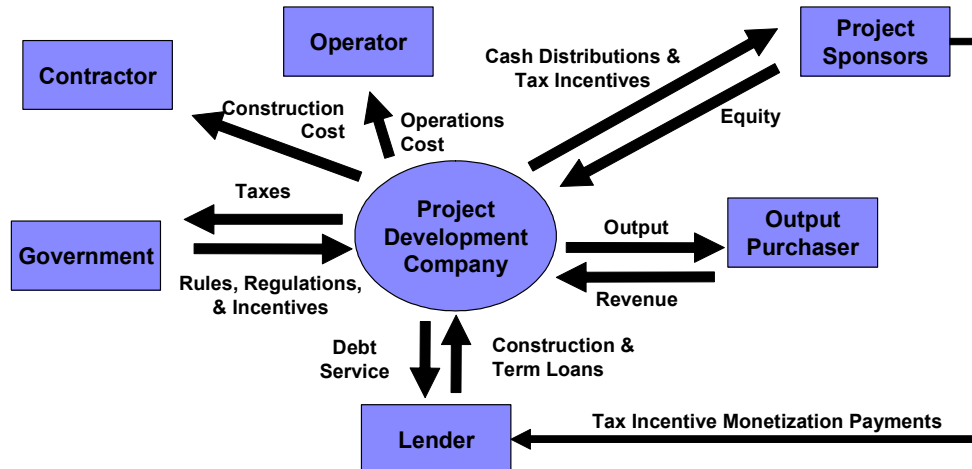


Figure 6-2
Development Approaches: Private Ownership

6.3 Public-Private Partnership

In this ownership approach, equity would be sourced as in the private ownership development options, but the debt portion of the financial structure would be a combination of debt provided by private sector and public sector sources, such as a state pension fund or trust fund. The private sector debt would be interest-only for the first 15 years. This combination of debt from these sources would lengthen the maturity of the debt and might improve the free cash flow at the front-end of the project. Figure 6-3 shows the key entities and cash flows. Advantages of this approach include the following:

- A novel solution to the debt portion of the capital structure would be used.
- The amortization schedules would be stretched.
- Stronger incentives would be provided to equity investors.

Disadvantages include the following:

- The private/public combination of debt is not used extensively.
- There is a long-term risk on the public sector lender.
- Terms need to be negotiated with private lenders.
- A longer-term PPA is needed.

6.4 Project Development Steps

Regardless of the ownership approach, the following development steps must be completed:

- Obtaining an independent engineer's due diligence report.
- Obtaining construction financing.
- Obtaining a commitment for take-out financing for equity and debt.

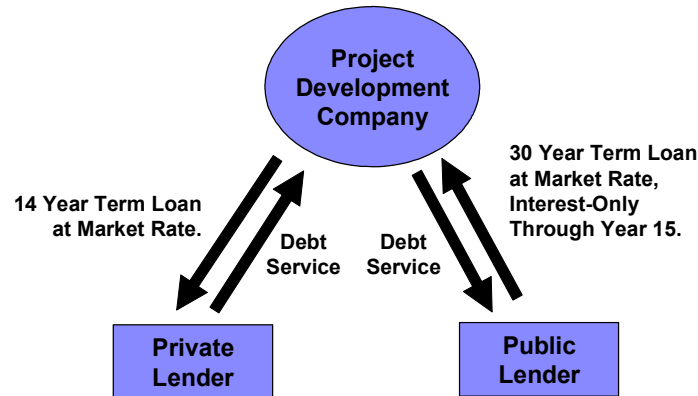


Figure 6-3
Development Approaches: Public-Private Partnership

- Negotiating and signing an EPC contract (as part of financial close).
- Performing actual construction of the project.
- Completing construction.
- Completing performance tests.
- Obtaining final certifications.
- Obtaining acceptance of project by owner/developer.
- Converting from construction financing to long-term financing.

The order of these tasks is not necessarily as listed above. Many of the activities are likely to be performed concurrently.

6.5 Anticipated Project Risks

Regardless of the approach, the following risks must be anticipated and mitigated:

- Cost overruns.
- Interest rate risks on loans.
- Delay during construction period.
- Failure to meet “on line” date in PPA.
- Failure of equipment to meet contract specifications.
- Failure of project to meet performance tests.
- Delays caused by litigation by third party (e.g., failure to meet permit or environmental specifications).
- Failure of subcontractor to deliver parts or services.
- Failure of plant to meet output specifications set forth in the project pro forma and in the EPC contract.

Risk mitigation options include the following:

- Fixed price.
- Completion guarantees.
- Performance guarantees.
- Liquidated damages (LDs) if completion and performance standards are not met.
- The interface of the EPC contract with warranties provided by equipment manufacturers.

If the fixed price option is used, the owner/developer would agree to a not-to-exceed price. If the price is higher than the agreed price, the contractor would be required to make up the difference from contingency accounts. To satisfy completion and performance guarantees, the EPC contractor must complete the project within a specific time frame (e.g., 20 months) and, upon substantial completion, the plant (after a startup period) would be required to operate (perform) according to specified performance goals (e.g., 95 percent of nameplate capacity for 14 days). Failure to meet these guarantees would result in schedule and/or performance LDs. Typically, total LDs are capped. To mitigate financial risk, the developer and the financial institutions must engage experienced project finance and tax attorneys. Equity investors need to be fully knowledgeable about the debt instruments and have a single source responsibility for all elements of the capital structure. Interest rates should be fixed or, should that not be possible, hedged. Finally, technical, environmental, and legal due diligence must be performed to ensure that the financing is compatible with the EPC contract and other project agreements.

The methodology used for the financial analysis was to study six technology configurations, two plant locations, six incentive packages and six development/financing approaches for a total of 432 financial analyses. These are shown on Figure 6-4. The related assumptions for the incentives packages, for the development/financing approaches, and for the locations/technology configurations are shown in Tables 6-1, 6-2 and 6-3, respectively.

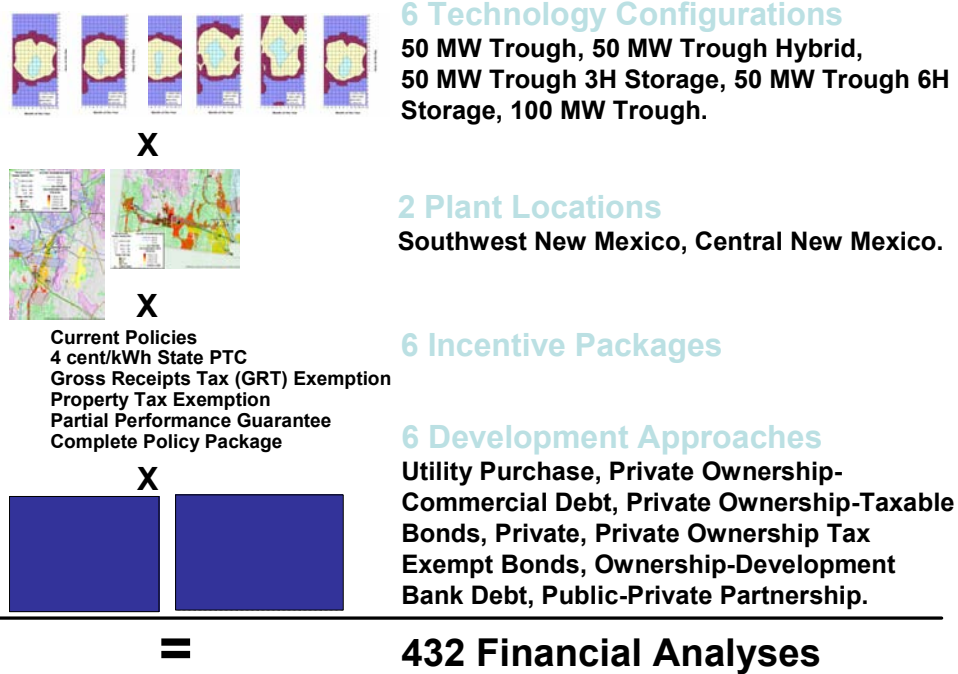


Figure 6-4
Financial Analysis Methodology

Table 6-1
Financial Analysis Assumptions (Part 1)

Policy Package Number	1	2	3	4	5	6
Policy Package Name	Current Policies	4 c/kWh State PTC	Performance Guarantee	GRT Exemption	Property Tax Exemption	Complete Policy Package
Assumption						
Property Tax Rate	0.50%	0.50%	0.50%	0.50%	0.00%	0.00%
State ITC Rate	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Federal ITC Rate	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
State PTC Rate (2004) (\$cents/kWh)	1	4	1	1	1	4
State PTC Length (Years)	10	10	10	10	10	10
Annual State PTC Quantity Cap (kWh)	400,000,000	400,000,000	400,000,000	400,000,000	400,000,000	400,000,000
Annual State PTC Amount Cap (\$/Year)	\$8,000,000	\$4,000,000	\$8,000,000	\$8,000,000	\$8,000,000	\$4,000,000
Federal PTC Rate (2004) (\$cents/kWh)	0	0	0	0	0	0
Federal PTC Length (Years)	10	10	10	10	10	10
PTC Discount Factor	100%	100%	100%	100%	100%	100%
Production Payment (cents/kWh)	0	0	0	0	0	0
Buy-Down (\$/w)	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Other Tax Credits (\$/Year)	\$0	\$0	\$0	\$0	\$0	\$0
Sales Tax Rate	6.00%	6.00%	6.00%	0.00%	6.00%	0.00%
EPC Premium Rate	15.00%	15.00%	0.00%	15.00%	15.00%	0.00%

Table 6-2
Financial Analysis Assumptions (Part 2)

Development Approach Number	1	2	3	4	5	6
Development Approach Name	Private-Commercial Debt	Utility Owned	Private-Taxable Bond	Private-Tax Exempt Bond	Private-Development Bank Debt	Public-Private Partnership
Assumption						
Firm Loan 1 Share	100.0%	100.0%	100.0%	100.0%	100.0%	50.0%
Firm Loan 1 Tenor	14	30	20	20	25	1
Firm Loan 2 Tenor	30	30	30	30	30	3
Construction Loan Rate Base	4.200%	4.200%	4.200%	4.200%	4.200%	4.200%
Firm Loan 1 Rate Base	4.200%	4.200%	4.200%	3.043%	4.200%	4.200%
Firm Loan 2 Rate Base	4.200%	4.200%	4.200%	4.200%	4.200%	4.200%
Construction Loan Rate Margin	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%
Firm Loan 1 Rate Base Margin	2.000%	1.500%	2.800%	2.029%	1.800%	2.000%
Firm Loan 2 Rate Base Margin	1.500%	1.500%	1.500%	1.500%	1.500%	2.000%
Firm Loan 2 Principle Start Year	1	1	1	1	1	1
Debt Share	65.0%	70.0%	70.0%	75.0%	75.0%	65.0%
Development Fee Rate	0.00%	7.00%	0.00%	0.00%	0.00%	0.00%
Loan Up front Fees	1.500%	1.500%	1.500%	1.500%	0.750%	1.500%
Loan Commitment Fees	0.500%	0.500%	0.500%	0.500%	0.750%	0.500%
Start DSR (Increments by 0.05 every 5 Years)	1.4	1.3	1.4	1.4	1.3	1.4
DSR Required	6	6	6	6	6	6
10-year Target MIRR	15%	12%	15%	15%	15%	15%

Table 6-3
Financial Analysis Assumptions (Part 3)

Technology Option Number	1	2	3	4	5	6
Technology Option Name	SW 50MW Trough	SW 50MW Trough Hybrid	SW 50MW Trough 3H Storage	SW 50MW Trough 6H Storage	SW 50MW Trough Dry Cooling	SW 100MW Trough
Assumption						
Total Capacity (MW)	50	50	50	50	50	100
Thermal Storage (hrs)	0	0	3	6	0	0
Net Capacity Factor (%)	26.23%	25.28%	31.47%	37.77%	26.42%	26.23%
Natural Gas Use (mmBtu/yr)	0	20,165	0	0	0	0
Raw Water Consumption (m3/yr)	446,296	428,338	536,245	642,654	34,737	892,592
Annual Labor Cost (\$k/yr)	\$2,411	\$2,366	\$2,477	\$2,547	\$2,746	\$2,411
Annual Materials & Services Cost (\$k/yr)	\$1,199	\$1,148	\$1,406	\$1,603	\$1,228	\$2,045
Total Capital Cost (\$k)	\$196,110	\$195,734	\$239,743	\$278,812	\$201,466	\$352,859

7.0 The Economic Impact of CSP In New Mexico

The objective of this task was to determine the economic impact of building one or more CSP plants in New Mexico and to compare these benefits to the cost of various state incentives. The economic analysis was performed by the BBER of the University of New Mexico.¹ Cost input data was provided by the B&V team. Three scenarios were analyzed: Scenario A is a 50 MW CSP plant; Scenario B is a 100 MW CSP plant; and Scenario C covers five 100 MW CSP plants built over 10 years. This section provides a brief summary of the BBER study input data, method, and results, and then provides a comparison of the economic benefits identified by BBER with the costs of incentives which might be provided by the state.

7.1 Cost Input Data

Data were provided for two CSP systems: a 50 MW plant with 6 hours' thermal storage and a 100 MW plant with 6 hours' thermal storage. While this information was provided to BBER in late September 2004, cost data for these plants have been adjusted slightly since that time. However, the results of the BBER study would change only slightly, and the results and conclusions remain valid.

The direct construction costs elements include the following:

- Structure and Improvements--Site, roads, warehouse, fence, water supply.
- Solar Field (Collector System)--Mirrors, heat conversion element (HCE), supports, erection, drives, piping, controls, foundations, other civil works, HTF, spares, freight.
- Steam Generation and Heat Exchange System--Heater, steam boiler, vessels, pumps, erection, freight.
- Thermal Energy Storage System--Heat exchangers, pumps, tanks, fluid, filter, piping, heat tracing, civil, and structural.
- Power Block--Turbine and generator, erection, electrical auxiliaries, freight.
- Balance of Plant--Water treatment, electrical, controls, erection, freight.

Table 7-1 summarizes the values provided for the construction cost elements. Figure 7-1 shows these values as a pie chart and the breakdown of the collector field costs.

¹ "The Economic Impact of Concentrating Solar Power in New Mexico," prepared by the University of New Mexico Bureau of Business and Economic Research (BBER), December 2004, for the New Mexico EMNRD.

Table 7-1
CSP Plant Investment (As used by BBER)

	50 MW	100 MW
Structures and Improvements	4,184,000	6,600,000
Collector System	113,507,000	221,024,000
Thermal Storage System	25,079,000	49,379,000
Steam Gen or Heat Exchange System	6,359,000	9,612,000
Power Block	22,937,000	37,260,000
Balance-of-Plant	<u>13,336,000</u>	<u>21,665,000</u>
Total Direct Costs	185,402,000	345,539,000
Engineering at 5 percent	9,270,000	17,277,000
Construction Management at 2.3 percent	<u>4,264,000</u>	<u>7,947,000</u>
Total Investment	198,936,000	370,763,000

Source: B&V Team, 2004.
UNM BBER, 2004.

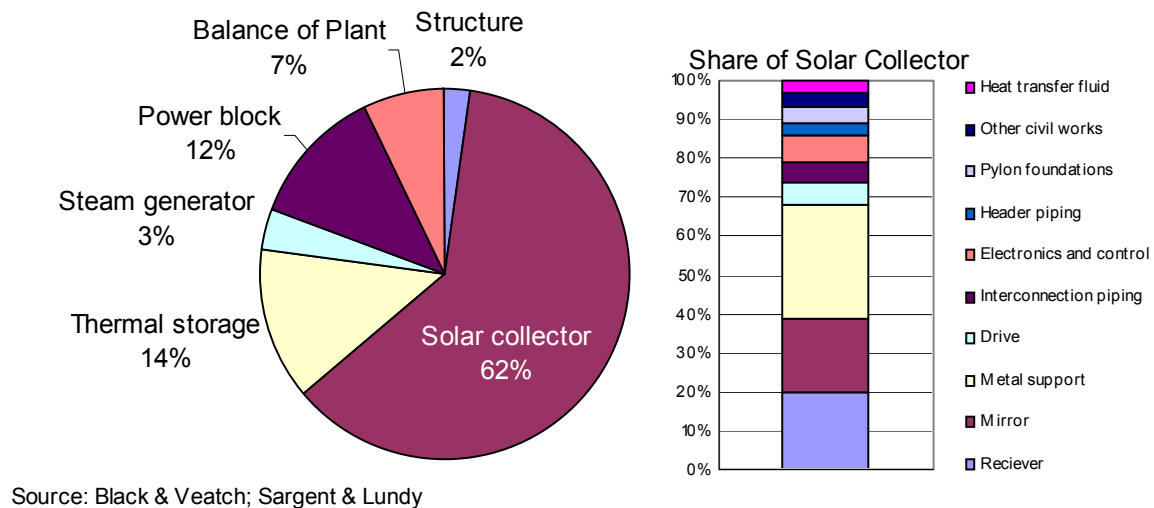


Figure 7-1
Component Cost Splits (As Used by BBER)

The labor skills required to build the plants were nonsupervisory (75 percent), supervisory (17 percent), administrative (5 percent), and engineering (3 percent). The construction period was 15 months for either size plant, and the construction rate was S-shaped, with 23 percent completed in the first 6 months, 57 percent completed in 9 months, and 90 percent completed in 12 months.

The O&M cost elements include the following:

- Service contracts for waste disposal, weed control, control computers, roads, sanitary services, office equipment, vehicles.
- Water usage for power block and mirror washing.
- Spares and equipment for thermal storage system, power generating system, balance-of-plant, steam generator, and structures.
- Solar field annual parts and materials--HCEs, mirrors, HTF makeup, ball joints, drives, and sun sensors.
- Average capital equipment--Vehicles, rigs, and containers.
- Miscellaneous--Phones, vehicle parts and supplies, office supplies, rental equipment, training, and travel.

Table 7-2 presents the O&M costs for a 50 MW CSP plant and Table 7-3 shows those costs for a 100 MW CSP plant. Thirty-five people are required to operate and maintain the 50 MW CSP plant, and an additional three are required for the 100 MW CSP plant. Like the construction labor skills, nonsupervisory skills dominate the mix. Table 7-4 shows the labor breakdown for the two plants.

Table 7-2 O&M Costs for a 50 MW CSP Plant (As Used by BBER)	
	50 MW, \$
Service Contracts	142,000
Chemicals/Water	63,000
Spares/Equipment	308,000
Miscellaneous	273,000
Solar Field	748,000
Capital	67,000
Overhead	1,123,000
Payroll	<u>1,604,000</u>
Total Annual Cost	4,328,000
Source: B&V Team, 2004. UNM BBER, 2004.	

Table 7-3 O&M Costs for a 100 MW CSP Plant (As Used by BBER)	
	100 MW, \$
Service Contracts	216,000
Chemicals/Water	125,000
Spares/Equipment	531,000
Miscellaneous	345,000
Solar Field	1,490,000
Capital	67,000
Overhead	1,211,000
Payroll	<u>1,729,000</u>
Total Annual Cost	5,714,000
Source: B&V Team, 2004. UNM BBER, 2004.	

Table 7-4 O&M Labor Breakdown (As Used by BBER)		
Function	50 MW	100 MW
Supervisor	4	4
Administration	4	4
Nonsupervisor	26	29
Engineers	<u>1</u>	<u>1</u>
Total	35	38
Source: B&V Team, 2004.		

The New Mexico Department of Labor data was used for salary rates. Data from Implan Pro 2.0, the input-output model utilized by BBER, was used for industries.² Other input data were based on surveys conducted of industries in the state.

² Minnesota IMPLAN Group, Inc., IMPLAN System (data and software), 1725 Tower Drive West, Suite 140, Stillwater, MN 55082 www.implan.com.

Table 7-5 summarizes the direct investments for the three scenarios. These include direct investment for construction and for O&M and the associated jobs.

Table 7-5 Direct Investments for Three Scenarios (As Used by BBER)				
	Construction Direct Investment	Jobs	O&M Direct Investment	Jobs
Scenario A	198,935,000	596	4,328,000	35
Scenario B	370,764,000	1,016	5,714,000	38
Scenario C	1,616,506,000	5,079	27,833,000	190

A 50 MW CSP plant would bring \$199 million into the state, would create 596 direct construction jobs, would need \$4.3 million per year and require 35 jobs for O&M. A 100 MW CSP plant would bring \$371 million into the state, create 1,016 jobs, and need \$5.7 million per year and require 38 jobs for O&M. Building 500 MW of CSP plants in New Mexico would bring \$1.6 billion into the state, create 5,079 jobs, need \$27.8 million, and create 190 jobs per year for O&M.

It was clear that New Mexico does not currently have the capability to provide all of the goods and services to build a CSP plant. It was assumed by BBER that if several plants were to be built in the state as part of a commitment to build some total capacity, then the local industry would evolve to the point where most of those needed goods and services would be provided locally. This industry evolution is shown in Table 7-6. The situation shown in this figure for the first plant is referred to as the “low” investment case, and the situation shown for the fifth plant is referred to as the “high” investment case. These two cases are described in Table 7-7.

7.2 Economic Impact Analysis

BBER’s key assumptions were (1) parabolic trough technology, (2) 6 hours’ thermal storage, (3) wet cooling, (4) pure solar (no hybrid fossil), (5) adequate transmission in place, and (6) the plant would be located in a rural area of the state. The methodology used by BBER was to determine the economic impact using the Implan Pro 2.0 model with regional purchase coefficients and multipliers. The fiscal impacts studies included taxes, cost of increased government services, and cost of any associated incentives that would be offered to any power plant built in the state.

Table 7-6
Industry Evolution in New Mexico (As Used by BBER)

Component	Plant 1	Plant 2	Plant 3	Plant 4	Plant 5
Structure	Y	Y	Y	Y	Y
Receiver	N	N	N	N	Y
Mirror	N	N	N	N	Y
Metal Support	N	N	Y	Y	Y
Drive	N	N	Y	Y	Y
Interconnection Piping	N	Y	Y	Y	Y
Electronics/Control	N	N	Y	Y	Y
Pylon Foundations	Y	Y	Y	Y	Y
Other Civil Work	Y	Y	Y	Y	Y
Thermal Storage	N	N	Y	Y	Y
Balance-of-Plant	Y	Y	Y	Y	Y
Header Piping	N	N	N	N	N
HTF	N	N	N	N	N
Steam Generator	N	N	N	N	N
Power Block	N	N	N	N	N
Engineering	N	N	N	N	N
Construction Management	N	N	N	N	N
Note: "Y" indicates industry is developed sufficiently to meet demand. Source: BBER industry analysis. UNM BBER, 2004.					

Table 7-7 BBER Scenarios		
	Low Investment	High Investment
Scenario A: 50 MW CSP Plant	Assumes primary contractor uses existing relationships for most equipment. Supervisors and engineers are treated as temporary.	Assumes existing industries supply as much as possible. All labor is treated as local.
Scenario B: 100 MW CSP Plant	Assumes primary contractor uses existing relationships for most equipment. Supervisors and engineers are treated as temporary.	Assumes existing industries supply as much as possible. All labor is treated as local.
	Plant One	Plant Five
Scenario C: Five 100 MW CSP Plants over 10 Years	Assumes primary contractor uses existing relationships for most equipment. Supervisors and Engineers are treated as temporary.	Industry supplying equipment and materials is fully evolved and majority of purchases are local.

Figure 7-2 shows the economic impacts of the direct expenditures associated with building the CSP plant. The direct expenditures would be for goods, services, and payroll. Some of these expenditures would be made to companies located outside the state and are termed “leakage.” Other expenditures would be made to local vendors, and the rest to households in the state. Local vendors would purchase goods and services from other local vendors and make payments to households. Those households would make local purchases, some of which would be imports.

The fiscal impact of building CSP plants would include increased tax revenues to state and local governments. These would arrive as increased personal and corporate income taxes, increased GRTs, increased compensating taxes on imported equipment, increased property taxes, and other taxes specific to electric utilities. These increases would have to be reduced by any increased costs of local and state government services.

The economic impacts of building a 50 MW CSP, a 100 MW CSP plant, and five 100 MW CSP plants are shown in Tables 7-8, 7-9, and 7-10.

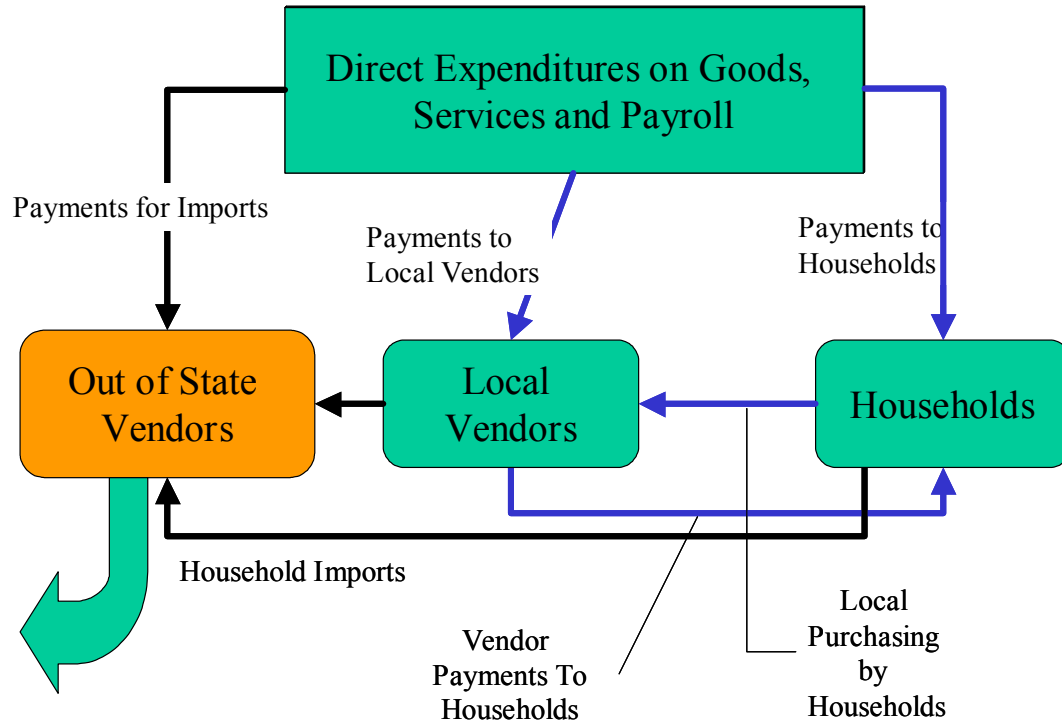


Figure 7-2
Simple Economy Flows
(Taken from BBER Presentation, December 2, 2004)

Table 7-8 Scenario A--50 MW CSP Plant			
	Construction Impact		Annual Operations Impact
	Low	High	
Employment	925	1,222	74
Income (\$ Million)	33.4	43.1	2.7
Output (\$ Million)	224.9	252.5	7.5
Fiscal Impact for 30 Year Life of CSP Plant			
Low (\$ Million)	104.0		
High (\$ Million)	110.2		
Source: BBER. UNM BBER, 2004.			

Table 7-9 Scenario B--100 MW CSP Plant			
	Construction Impact		Annual Operations Impact
	Low	High	
Employment	1,588	2,119	85
Income (\$ Million)	57.4	74.7	3.1
Output (\$ Million)	416.0	465.4	9.5
Fiscal Impact for 30 Year Life of CSP Plant			
Low (\$ Million)	118.5		
High (\$ Million)	129.7		
Source: BBER. UNM BBER, 2004.			

Table 7-10 Scenario C--Five 100 MW CSP Plants		
	Construction Impact	Annual Operations Impact
Employment	11,696	397
Income (\$ Million)	416.4	16.1
Output (\$ Million)	2,246.9	46.1
Fiscal Impact for 30 Year Life of CSP Plant		
Total for All Plants (\$ Million)	759.7	
Source: BBER. UNM BBER, 2004.		

7.3 Conclusions

The following conclusions are drawn from the BBER report:

- Building a CSP plant, regardless of size, would have a positive economic impact and would increase the state's tax revenues. Creating a CSP manufacturing industry in New Mexico would add additional jobs and economic activity for the state.
- A 50 MW CSP plant built in New Mexico would create \$225 to \$252 million of economic activity in the state and would create between 925 and 1,222 jobs, depending on the local content. Over its 30 year design life, 74 jobs would be created and the state would gain \$7.5 million for each year of its operation. The state's tax revenues would increase by \$104 to \$110 million.
- A 100 MW CSP plant built in New Mexico will create \$416 to \$465 million of economic activity in the state and would create between 1,588 and 2,119 jobs, depending on the local content. Over its 30 year design life, 85 jobs would be created and the state would gain \$9.5 million for each year of its operation. The state's tax revenues would increase by \$118 to \$130 million.
- Building five 100 MW CSP plants in New Mexico would create \$1.6 billion of economic activity in the state and create 11,696 jobs. Over its 30 year design life, 397 jobs would be created and the state would gain \$46 million for each year of its operation.
- If a CSP manufacturing industry evolves in New Mexico, every 100 MW of CSP plant built outside the state, either elsewhere in the southwestern United States or overseas, would create 1,406 high quality jobs and bring \$41.4 million into the state.

8.0 Project Development Models

The objective of this task was to create a set of viable CSP development scenarios based on the analysis conducted in the previous six tasks. These scenarios were to include a minimum of three sites for at least two CSP technologies, with a minimum of two financing strategies, selling power into the most attractive in-state and out-of-state markets.

Figure 8-1 illustrates the development model approach.

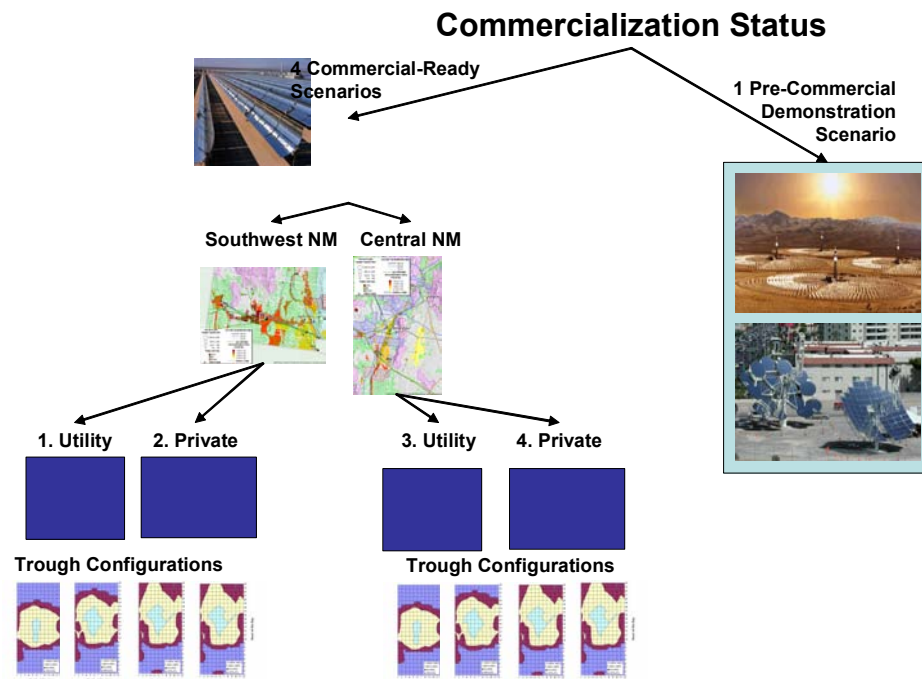


Figure 8-1
Development Scenario Approach

Four commercial scenarios and one precommercial scenario were evaluated. Each of the scenarios is contingent upon a utility issuing a 10 to 12 cents/kWh long-term (25 to 30 year) PPA. The scenarios are described as follows:

- Southwest Utility Purchase Trough:
 - Technology--Parabolic trough with 6 hours of thermal storage, with and without dry cooling.
 - Siting--Southwest Location (sites near Deming and Lordsburg).
 - Financing--Utility Purchase model using a 50/50 debt-to-equity ratio.

- Market--Las Cruces/El Paso.
- Incentives--Range of policies from current environment to full package were analyzed (six discrete cases).
- Southwest Private Ownership Trough:
 - Technology--Parabolic trough with 6 hours of thermal storage, with and without dry cooling.
 - Siting--Southwest Location (sites near Deming and Lordsburg)
 - Financing--Private ownership with 50/50 debt-to-equity ratio. Sources of capital would be \$50 million NM State Investment Council (SIC) (equity) + \$50 million developer (equity) + \$50 million North American Development Bank (NADB) (30 year debt, with 15 year interest-only) + \$50 million taxable bonds (20 year).
 - Market--Las Cruces/El Paso.
 - Incentives--Range of policies from current environment to full package were analyzed (six discrete cases).
- Central Utility Purchase Trough:
 - Technology--Parabolic trough with 6 hours of thermal storage, with and without dry cooling.
 - Siting--Central Location (site near Belen).
 - Financing--Utility Purchase model using a 50/50 debt-to-equity ratio.
 - Market--Albuquerque.
 - Incentives--Range of policies from current environment to full package were analyzed (six discrete cases).
- Central Private Ownership Trough:
 - Technology--Parabolic trough with 6 hours of thermal storage, with and without dry cooling.
 - Siting--Central Location (site near Belen).
 - Financing--Private ownership with 50/50 debt-to-equity ratio. Sources of capital would be \$50 million NM SIC (equity) + \$50 million developer (equity) + \$35 million New Mexico Finance Authority (NMFA) + \$65 million taxable bonds (20 year).
 - Market--Albuquerque.
 - Incentives--Range of policies from current environment to full package were analyzed (six discrete cases).

- Demonstration Project:
 - Technology--14 MW power tower or dish-Stirling demonstration systems.
 - Siting--Central or Southwest Location.
 - Financing--Uncertain, but would probably require state and federal grants.
 - Market--Albuquerque or Las Cruces/El Paso.
 - Incentives--Appropriate to demonstration project.

8.1 Scenario 1: Southwest Trough Utility Purchase

- Electricity Cost: \$88.90 - 120.40/MWh
- Capital Investment: \$252 - \$288 million

Southwest New Mexico has the most favorable solar resources of potential sites in New Mexico and a strong need for economic development. Parabolic troughs have a 15 year history of commercial operation and provide the lowest COE, of the options studied, for an acceptable level of risk. The utility purchase strategy is an attractive development approach because of low cost of debt and favorable equity terms provided by utilities. It is estimated that with highly favorable incentives, a 50 MW trough with wet cooling located in southwest New Mexico would have a first-year COE of \$88.90/MWh under this development scenario. The primary challenges associated with this development scenario include the presence of transmission congestion into Las Cruces/El Paso and the potential unwillingness of utilities to own and operate a large-scale solar power plant.

8.1.1 Action Items

Because of a constraint at the 345/115 kV transformation into the Las Cruces/El Paso market, there is significant uncertainty about whether solar power could be sold into this market. A transmission study must be conducted by the transmission-owning entities to resolve this uncertainty. A transmission study must be pursued immediately to fully explore the prospects for the development of a new solar power plant in southwest New Mexico.

Increased state incentives would be required to reduce the cost and increase the financial attractiveness of the 50 MW parabolic trough plant. The refundable 10 year, 2 cents/kWh PTC represents the highest value incentive. Enactment of this incentive should take precedence over other action items. A GRT exemption, a property tax exemption, and a partial performance guarantee would also improve the financial attractiveness of a prospective solar power plant and should also be pursued.

The formation of a consortium of utilities with a willingness to invest in the development of one or more large-scale solar power plants is an important action item

that must be pursued to advance this development scenario. It may be necessary to seek the participation of regional utilities that have an interest in large-scale solar power because of state-specific renewable portfolio standard (RPS) programs or to satisfy other objectives. Ultimately, New Mexico may not have the appropriate level of energy demand, transmission capability, and long-term utility support required to advance the development of one or more large-scale solar power plants.

8.1.2 Location

Southwest New Mexico, which has been identified as Location 2 within the context of this study, has the most favorable solar resources, as well as the strongest need for economic development. The DNI solar resource for this location is estimated to be 7.28 kWh/m²/day. It has been modeled as the Typical Meteorological Year Version 2 (TMY2) data for El Paso, scaled proportionately to the satellite data for Location 2.

As stated above, it is estimated that with highly favorable incentives, a 50 MW trough with wet cooling in Location 2 in southwest New Mexico would have a first-year COE of \$99.80/MWh, compared to a first-year COE of \$94.50/MWh at Location 1 in central New Mexico.¹ The improvement of \$5.60/MWh is due entirely to the more favorable solar resources in southwest New Mexico. Three sites have been identified within Location 2: Site 1, immediately northwest of Deming; Site 2, 12 miles southeast of Lordsburg; and Site 3, immediately northeast of Lordsburg.

8.1.3 Technology

It is recommended that a parabolic trough plant with 6 hours of thermal storage and with dry or wet cooling, depending upon the need for reduced water consumption, be developed. Parabolic troughs have a 15 year history of commercial operation and provide the lowest first-year COE and a level of risk that falls within the tolerance of the financial markets, as long as commonly accepted risk reduction strategies are employed. Thermal storage would enable a plant to provide guaranteed capacity and to shift energy production to the highest value periods.

8.1.4 Financial Analysis

Table 8-1 shows the cost, revenue, performance, and water consumption estimates for four configurations of 50 MW parabolic trough plants located in southwest New Mexico.

¹ Throughout this brief, it was assumed that the solar plant would become operational in 2007 and that the COE would escalate at 2 percent per year thereafter.

Table 8-1
Southwest 50 MW Parabolic Trough Cost, Revenue, and Performance Estimates

Technology	Thermal Storage (hours)	Cooling Technology	Capital Cost (\$/kW)	O&M (\$/MWh)	Energy Production (Thousand MWh)	Water Consumption (Thousand Gallons)	Average Annual Revenue (\$/kW/year)	First-Year COE w/Full Incentives* (\$)
Parabolic Trough	0	Wet	3,920	31	115 (26.2%)	446	89	96.00
Parabolic Trough	3	Wet	4,800	28	138 (31.5%)	536	104	94.00
Parabolic Trough	6	Wet	5,580	25	165 (37.8%)	643	127	88.90
Parabolic Trough	6	Dry	5,660	28	164 (37.5%)	49	126	92.40

*Under a utility purchase development scenario assuming 30 year debt at 5 percent. Incentive package includes a 2 cents/kWh state PTC, a performance guarantee, a property tax exemption, and a GRT exemption in addition to existing incentives.

The plant with 6 hours of thermal storage is recommended because of the reduced first-year COE and higher expected revenues. The cooling technology selection is a function of the value of reduced water consumption. It is estimated that the parabolic trough with 6 hours' storage and wet cooling would consume approximately 643,000 gallons per year. It is estimated that the same plant with wet cooling would consume approximately 49,000 gallons per year. Since the first-year energy production costs with wet and dry cooling are estimated at \$88.90/MWh and \$92.40/MWh, respectively, 594,000 gallons of water consumption per year could be avoided for an increased production cost of \$3.50/MWh.

8.1.5 Market

The preferred option is to deliver power to the nearest wholesale customer, which, in this case, means delivery to the Las Cruces/El Paso load center. Beyond this, a second less favorable option would be to transmit energy north to Albuquerque. However, at present, energy could be transferred to Albuquerque only on a non-firm basis. A third option would be to transmit energy out of state into Tucson and Phoenix and possibly beyond. Although firm power transfer capability exists into Tucson and Phoenix through 2007, this option is complicated by transmission bottlenecks throughout the Southwest.

Emerging voluntary and compliance REC markets throughout the western United States have the potential to provide an additional revenue source for the non-energy attributes of solar plant output. However, these markets are not yet well defined and are generally illiquid. As a result, it is unlikely that REC revenue could be used to attract financing.¹

Regardless of the ultimate market for solar power, the expected revenue from energy sales will be far short of the required revenue. It is estimated that an annual payment in the range of \$250 to \$300/kW would be required to cover operating expenses, service debt, pay taxes, and provide a return to equity investors. Energy sales would account for approximately 50 percent of this revenue even in the most optimistic scenario.

8.1.6 Development Approach

The utility purchase strategy is an attractive development approach because of the low cost of debt and favorable debt terms offered by publicly owned utilities. Under this approach, the solar plant would be fully developed by an independent power producer

¹ Refer to Draker, et al. (2004) "Markets for Bulk Solar Power: Issues and Opportunities Associated With Serving Markets Outside of New Mexico With New Mexico Solar Power," Center for Resource Solutions, San Francisco, CA, November 2004; and Draker, et al. (2004) "New Mexico Concentrating Solar Power Feasibility Study: Issues and Opportunities Associated With the Use of Renewable Energy Certificates As An Energy Marketplace Currency," Center for Resource Solutions, San Francisco, CA, November 2004.

and then sold directly to one or more New Mexico utilities for the cost of construction, plus a 6 percent development fee. The utility consortium would be expected to finance the purchase using a 50:50 debt-to-equity capital structure. The debt terms would vary, but debt terms could be as favorable as 30 year debt with a 5.7 percent interest rate. Equity terms would vary, but equity terms could be as favorable as a 12 percent expected rate of return.

8.1.7 Incentives

Under this development scenario, favorable state and federal incentives would be required to move the COE toward a competitive level. Clearly, greater levels of public assistance would alleviate the financial burden of the plant owner and/or power purchaser. Under the current policy environment, it is estimated that a 50 MW trough with wet cooling located in Location 2 would have a COE of \$120.40/MWh. If the 10 year state PTC is increased to 2 cents/kWh, then the COE would fall to \$110.60/MWh. Under a highly favorable policy package that included the 2 cents/kWh PTC, a state GRT, a property tax exemption, and a state-sponsored partial performance guarantee that reduces risk to the EPC contractor, the COE would drop to \$88.90/MWh. Table 8-2 shows the impact of each incentive option.

Table 8-2 Incentive Options for Southwest 50 MW Parabolic Trough with 6 Hours Storage and Wet Cooling*			
Incentive	First-Year COE (\$/MWh)	Difference from Current Policy Environment (\$/MWh)	Cost to Government (Million \$)
Current Policies	120.40		16.5 over 10 years.
2 cents/kWh Refundable State PTC	110.60	9.80	33.10 over 10 years.
Performance Guarantee	106.30	14.10	No cost if plant performs as expected.
GRT Exemption	112.40	8.00	No cost if plant is not constructed because there are no incentives.
Property Tax Exemption	111.30	9.10	No cost if plant is not constructed because there are no incentives.
All Incentives	88.90	3.15	33.10 over 10 years for 2 cents/kWh PTC.
*Under a utility purchase development scenario assuming 30 year debt at 5 percent.			

8.1.8 Benefits

A recent, companion study by the UNM BBER indicates that development of a 50 MW solar power plant would result in the creation of between 925 and 1,222 construction jobs and would inject between \$225 and \$250 million into the state economy.¹ Ongoing plant operations would yield 74 new jobs and would inject \$7.5 million into the state economy annually (or \$225 million over the 30 year life of the plant.) Taken together, this means that a 50 MW parabolic trough would be expected to inject at least \$450 million into the state economy over its lifetime. Further, BBER estimates that a 50 MW parabolic trough plant would have a net positive fiscal impact of between \$104 and \$110 million over the life of the plant.

If the plant performs as expected, then the cost of the state PTC would represent the only direct costs to the state for the development of a 50 MW parabolic trough plant. If the PTC were to be increased to 2 cents/kWh as currently proposed, then the PTC cost would total \$33 million over the 10 year PTC eligibility period. Thus, for \$33 million in lost tax revenue over a 10 year period, a 50 MW parabolic trough plant would inject \$450 million into the state economy while yielding a positive fiscal impact of at least \$104 million. It should be noted that this analysis excludes the positive benefits associated with decreased reliance on volatile natural gas and the environmental advantages of reduced local air pollutants and greenhouse gas emissions; it also excludes the economic costs associated the reduced competitiveness of New Mexico businesses as a result of solar power purchases.

8.1.9 Barriers

There are several barriers associated with this development scenario. First, and perhaps most importantly, transmission congestion is a serious issue for any new power plant located in southwest New Mexico and transmitting power into the Las Cruces/El Paso load center. Significant constraints occur in the 345/115 kV transformation into Las Cruces. Therefore, it is unlikely that the power could be sold using this path unless this power were used in lieu of other imports. The extent of the problem and the ultimate relevance for a 50 MW parabolic trough plant cannot be fully assessed until a new transmission study is performed by the transmission-owning entities in the region. Second, obtaining water rights may be challenging. Third, there are barriers associated with the utility purchase development approach. Utilities generally favor least-cost

¹ Bureau of Business and Economic Research (2004), "The Economic Impact of Concentrating Solar Power in New Mexico," University of New Mexico Bureau of Business and Economic Research (BBER), Albuquerque, NM, November 2004.

supply options in lieu of more expensive renewable power options. Solar power options may be viewed unfavorably by these load-serving entities because of the higher cost of solar power relative to other alternatives such as wind, biomass, and geothermal. Against this backdrop, finding a utility willing to purchase and operate a 50 MW solar power plant will be challenging. The most attractive option may be to assemble a consortium of utilities to share the costs and risks associated with the 50 MW parabolic trough. There is potential for the development of a consortium of utilities throughout the Southwest that would be interested in the development of large-scale solar power for both voluntary and RPS compliance purposes.

8.2 Scenario 2: Southwest Trough Private Ownership

- Electricity Cost: \$93.80 - \$178.60/MWh
- Capital Investment: \$239 - \$289 million

Southwest New Mexico has the most favorable solar resources of potential sites in New Mexico and a strong need for economic development. CSP parabolic troughs have a 15 year history of commercial operation and provide the lowest COE for an acceptable level of risk. The private ownership strategy may be a viable development approach with the assistance of state entities such as the NMFA and the SIC, which may be able to provide debt or equity capital at favorable terms. Other financial institutions such as the NADB may also represent prospective funding sources that could be tapped to supplement private capital sources. It is estimated that with highly favorable incentives, a 50 MW trough with wet cooling located in southwest New Mexico would have a first-year COE of \$93.80/MWh under this development scenario, assuming 25 year debt at 6 percent. The primary challenges associated with this development scenario include raising sufficient debt and equity capital to fund project construction and the need for a transmission study to determine the impact of congestion into Las Cruces/El Paso.

8.2.1 Action Items

First, because of a constraint at the 345/115 kV transformation into the Las Cruces/El Paso market, there is significant uncertainty about whether solar power could be sold into this market. A transmission study must be conducted by the transmission owning entities to resolve this uncertainty. Next, increased state incentives are required to reduce the cost and increase the financial attractiveness of the 50 MW parabolic trough plant. The refundable 10 year, 2 cents/kWh PTC represents the highest value incentive. Enactment of this incentive should take precedence over other action items. A GRT exemption, a property tax exemption, and a partial performance guarantee would also improve the financial attractiveness of a prospective solar power plant and should be

pursued. Finally, in addition to the promotion of state incentives, additional state-level legislative changes could be useful in promoting a large-scale solar project in New Mexico. In particular, it may be necessary to increase the \$20 million per project cap that the SIC currently faces when purchasing investment-grade bonds. Further, raising the 10 percent limit in SIC's Private Equity Investment Program (which effectively places a \$20 million per project cap on equity contributions) would open up additional equity capital to support this project. Finally, an appropriation on the order of \$50 million or more would provide the conditions under which the Statewide Economic Development and Finance Act (SWEDFA) could be used to support the development of a new large-scale solar power project in New Mexico.

8.2.2 Location

Southwest New Mexico, which has been identified as Location 2 within the context of this study, has the most favorable solar resources, as well as the strongest need for economic development. The DNI solar resource for this location is estimated to be 7.28 kWh/m²/day. It has been modeled as the TMY2 data for El Paso, scaled proportionately to the satellite data for Location 2.

It is estimated that with highly favorable incentives, a 50 MW trough with wet cooling located in Location 2 under the private ownership development approach (assuming 25 year debt at 6 percent) would have a first-year COE of \$93.80/MWh, compared to a first-year COE of \$99.80/MWh at Location 1 in central New Mexico under the same assumptions.¹ The improvement of \$6.00/MWh is due entirely to the more favorable solar resources in southwest New Mexico. Three sites have been identified within Location 2: Site 1, immediately northwest of Deming; Site 2, 12 miles southeast of Lordsburg; and Site 3, immediately northeast of Lordsburg.

8.2.3 Technology

It is recommended that a parabolic trough plant with 6 hours of thermal storage and with dry or wet cooling, depending upon the need for reduced water consumption, be developed. Parabolic troughs have a 15 year history of commercial operation and provide the lowest first-year COE and a level of risk that falls within the tolerance of the financial markets, as long as commonly accepted risk reduction strategies are employed. Thermal storage would enable a plant to provide guaranteed capacity and to shift energy production to the highest value periods.

¹ Throughout this brief, it was assumed that the solar plant would become operational in 2007 and that the COE would escalate at 2 percent per year thereafter.

8.2.4 Financial Analysis

Table 8-3 shows the cost, revenue, performance, and water consumption estimates for four configurations of 50 MW parabolic trough plants located in southwest New Mexico.

The plant with 6 hours of thermal storage is recommended because of the reduced first-year COE and higher expected revenues. The cooling technology selection is a function of the value of reduced water consumption. It is estimated that the parabolic trough with 6 hours' storage and wet cooling would consume approximately 643,000 gallons per year. It is estimated that the same plant with wet cooling would consume approximately 49,000 gallons per year. Since the first-year energy production costs with wet and dry cooling are estimated at \$93.80/MWh and \$97.50/MWh, respectively, 594,000 gallons of water consumption per year could be avoided for an increased production cost of \$3.70/MWh.

8.2.5 Market

The preferred option is to deliver power to the nearest wholesale customer, which, in this case, means delivery to the Las Cruces/El Paso load center. A second less favorable option would be to transmit energy north to Albuquerque. However, at present, energy could be transferred to Albuquerque only on a non-firm basis. A third option would be to transmit energy out of state into Tucson and Phoenix and possibly beyond. Although firm power transfer capability exists into Tucson and Phoenix through 2007, this option is complicated by transmission bottlenecks throughout the Southwest.

Emerging voluntary and compliance REC markets throughout the western United States have the potential to provide an additional revenue source for the non-energy attributes of solar plant output. However, these markets are not yet well defined and are generally illiquid. As a result, it is unlikely that REC revenue can be used to attractive financing.¹

Regardless of the ultimate market for solar power, the expected revenue from energy sales will be far short of the required revenue. It is estimated that an annual payment in the range of \$250 to \$300/kW would be required to cover operating expenses, service debt, pay taxes, and provide a return to equity investors. Energy sales would account for approximately 50 percent of this revenue even in the most optimistic scenario.

¹ Refer to Draker, et al. (2004) "Markets for Bulk Solar Power: Issues and Opportunities Associated With Serving Markets Outside of New Mexico With New Mexico Solar Power," Center for Resource Solutions, San Francisco, CA, November, 2004; and Draker, et al. (2004) "New Mexico Concentrating Solar Power Feasibility Study: Issues and Opportunities Associated With the Use of Renewable Energy Certificates As An Energy Marketplace Currency," Center for Resource Solutions, San Francisco, CA, November 2004.

Table 8-3
Southwest 50 MW Parabolic Trough Cost, Revenue, and Performance Estimates

Technology	Thermal Storage (hours)	Cooling Technology	Capital Cost (\$/kW)	O&M (\$/MWh)	Energy Production (Thousand MWh)	Water Consumption (Thousand Gallons)	Average Annual Revenue (\$/kW/year)	First-Year COE w/Full Incentives* (\$)
Parabolic Trough	0	Wet	3,920	31	115 (26.2%)	446	89	101.00
Parabolic Trough	3	Wet	4,800	28	138 (31.5%)	536	104	99.10
Parabolic Trough	6	Wet	5,580	25	165 (37.8%)	643	127	93.80
Parabolic Trough	6	Dry	5,660	28	164 (37.5%)	49	126	97.50

*Under a private ownership development scenario assuming 25 year debt at 6 percent. Incentive package includes a 2 cents/kWh state PTC, a performance guarantee, a property tax exemption, and a GRT exemption in addition to existing incentives.

8.2.6 Development Approach

The private ownership strategy may be a viable development approach with the assistance of state entities such as the NMFA and the SIC, which may be able to provide debt or equity capital at favorable terms. In addition, other financial institutions such as the NADB may also represent prospective funding sources that could be tapped to supplement private capital sources. Under this approach, the project would be developed by a private sector developer who would fund the development cost. The project would be financed with a combination of equity and debt. Debt could be sourced from (1) a commercial bank, (2) a taxable bond issuance, (3) a development bank, or (4) a public entity such as the federal or state government. A variation of the above debt options would be to “credit enhance” the debt through a letter of credit. The equity would be raised from private sector investors who would have a need for the tax benefits from the project.

8.2.7 Debt

Debt terms would vary by source. A commercial bank would be expected to provide 14 year debt with a 6.2 percent interest rate. If debt were raised through a private taxable-bond issuance, then the debt term might be as long as 20 years with an interest rate of 7 percent. Along with financial market participants, the state of New Mexico is a prospective buyer through such a bond issuance, since the SIC is authorized to purchase investment-grade bonds up to a \$20 million cap per project. This cap can be increased to \$50 for AAA bonds. This raises the intriguing possibility that a solar project could achieve a AAA credit rating by purchasing insurance against loan default. The merits of this possibility will depend upon the cost of insurance relative to the value of an enhanced credit rating.

NADB may represent the lowest-cost source of debt for a new large-scale solar project in southwest New Mexico. NADB, which funds infrastructure projects within 100 kilometers of the US-Mexico border, represents an interesting prospective funding source. Although terms vary considerably depending upon the project’s credit risk, under the most favorable circumstance, NADB might be able to offer 25 year debt at a 6 percent interest rate. It should be noted that NADB cannot accept exposure of more than 50 percent of the total capital costs, which will limit project debt share to 50 percent unless other debt sources are tapped.

It may be possible to combine debt funding from two or more sources. The two forms of debt could even be structured in a complementary manner. One intriguing option is to structure a secondary source of debt as a principle-only loan during the repayment term of the primary debt source. For example, a conventional commercial

bank loan with a 14 year repayment period could be coupled with a 25 year NADB loan that allows for interest-only payments during years 1 through 14. Structuring two sources of debt in this manner would reduce the debt repayment burden substantially, thereby improving the economics of a prospective large-scale solar power project.

8.2.8 Equity

Equity terms would be expected to be in accordance with market rates. Analysis indicates that 15 percent represents the minimum 15 year hurdle rate for a large-scale solar project. It must be acknowledged that this hurdle rate may represent the low side, given the perceived risks associated with the development of a new large-scale solar power project. Again here, on the equity side, the state of New Mexico may have an opportunity to play a role in buttressing private equity dollars with additional public-sector funds. Through the New Mexico Private Equity Investment program, the State Investment Officer (SIO) may invest in private equity funds (upon approval of the Private Equity Investment Advisory Council and the SIC). This means that the state could take an equity position in a prospective new large-scale solar power project located in New Mexico. However, the state investment may represent no more than 51 percent of the equity in a particular project, and only 10 percent of the total money available for this state investment program (approximately \$20 million) may be invested in any one company. It is estimated that this 10 percent limit may have to be increased to at least 25 percent to provide a level of equity that would facilitate the development of a new large-scale solar power project in New Mexico.

Finally, it should be noted that the NMFA has a wide range of financial assistance options under New Mexico's SWEDFA, which was passed in 2004. Through SWEDFA, NMFA has the ability to provide debt or equity to a new large-scale solar power project in New Mexico that promotes statewide economic development. SWEDFA also provides NMFA with the ability to provide other forms of financial assistance such as grants and loan guarantees. However, funds have yet to be appropriated to support SWEDFA. It is expected that funds will be appropriated during the 2005 legislative session. It is believed that an appropriate level of \$50 million or more would be required to provide the conditions under which SWEDFA could be used to support the development of a new large-scale solar power project in New Mexico.

Table 8-4 shows the first-year COE for a 50 MW parabolic trough with 6 hours of storage and wet cooling located in southwest New Mexico under the private ownership development approach for a variety of different debt-equity funding source combinations. The obvious conclusion from Table 8-4 is that developers should seek long-term debt at the lowest possible interest rate. Because solar power projects are extremely capital

intensive, debt financing terms are the single largest factor in determining a solar plant's cost of production.

Table 8-4 First-Year COE for a Southwest 50 MW Parabolic Trough with 6 Hours' Storage			
Debt	Equity	Capital Structure (Debt:Equity)	First-Year COE With Full Incentives (\$/MWh)
Commercial bank debt with a 14 year term at 6.2 percent	Strategic and/or passive tax investor(s) with a 15 percent hurdle rate	50:50	122.60
Private taxable bond issuance with a 20 year term at 7 percent	Strategic and/or passive tax investor(s) with a 15 percent hurdle rate	50:50	109.90
Development agency or other quasi-public financing with a 25 year term at 5.7 percent	Strategic and/or passive tax investor(s) with a 15 percent hurdle rate	50:50	93.80

8.2.9 Incentives

Under this development scenario, favorable state and federal incentives would be required to move the COE toward a competitive level. Clearly, greater levels of public assistance would alleviate the financial burden of the plant owner and/or power purchaser. Under the current policy environment, it is estimated that a 50 MW trough with wet cooling located in Location 2 would have a first-year COE of \$138/MWh. If the 10 year state PTC is increased to 2 cents/kWh, then the first-year COE would fall to \$117/MWh. Under a highly favorable policy package that includes the 2 cents/kWh PTC, a state GRT, a property tax exemption, and a state-sponsored partial performance guarantee that reduces risk to the EPC contractor, the first-year COE would drop to \$94/MWh. Table 8-5 shows the impact of each incentive option.

8.2.10 Benefits

A recent, companion study by the UNM BBER indicates that development of a 50 MW solar power plant would result in the creation of between 925 and 1,222 construction jobs and would inject between \$225 and \$250 million into the state

Table 8-5 Incentive Options for Southwest 50 MW Parabolic Trough with 6 Hours' Storage and Wet Cooling*			
Incentive	First-Year COE (\$/MWh)	Difference from Current Policy Environment (\$/MWh)	Cost to Government (Million \$)
Current Policies	138.00		\$16.5 over 10 years.
2 cents/kWh Refundable State PTC	116.60	21.40	\$33.10 over 10 years.
Performance Guarantee	121.50	16.50	No cost if plant performs as expected.
GRT Exemption	128.50	9.50	No cost if plant is not constructed because there are no incentives.
Property Tax Exemption	128.70	9.30	No cost if plant is not constructed because there are no incentives.
All Incentives	93.80	44.50	\$33.10 over 10 years for 2 cents/kWh PTC.
*Under a private ownership development scenario assuming 25 year debt at 6 percent.			

economy.¹ Ongoing plant operations would yield 74 new jobs and would inject \$7.5 million into the state economy annually (or \$225 million over the 30 year life of the plant.) Taken together, this means that a 50 MW parabolic trough would be expected to inject at least \$450 million into the state economy over its lifetime. Further, BBER estimates that a 50 MW parabolic trough plant would have a net positive fiscal impact of between \$104 and \$110 million over the life of the plant.

If the plant performs as expected, then the cost of the state PTC would represent the only direct costs to the state for the development of a 50 MW parabolic trough plant. If the PTC is increased to 2 cents/kWh as currently proposed, then the PTC cost would total \$33 million over the 10 year PTC eligibility period. Thus, for \$33 million in lost tax revenue over a 10 year period, a 50 MW parabolic trough plant would inject \$450 million into the state economy while yielding a positive fiscal impact of at least \$104 million. It should be noted that this excludes the positive benefits associated with decreased reliance

¹ Bureau of Business and Economic Research (2004), "The Economic Impact of Concentrating Solar Power in New Mexico," University of New Mexico Bureau of Business and Economic Research (BBER), Albuquerque, NM, November 2004.

on volatile natural gas and the environmental advantages of reduced local air pollutants and greenhouse gas emissions; it also excludes the economic costs associated the reduced competitiveness of New Mexico businesses as a result of solar power purchases.

8.2.11 Barriers

Between \$239 and \$289 million in equity and debt capital would be required to develop a new 50 MW parabolic trough plant in southwest New Mexico. Raising this level of capital would be a formidable task, particularly in light of the limited familiarity that capital markets have with large-scale solar power technologies. Although parabolic trough plants have a track record of commercial success, limited development over the last 15 years has increased the perceived risk associated with the technology. As a result, debt funding may be difficult to obtain, particularly through traditional lending sources such as commercial banks. On the equity side, there is a limited pool of developers who have the ability to assume a substantial equity stake in a new project. Further, these developers generally do not have the tax base necessary to take full advantage of the federal and state tax benefits available to solar power project owners.

Transmission congestion is a serious issue for any new power plant located in southwest New Mexico and transmitting power into the Las Cruces/El Paso load center. Significant constraints occur in the 345/115 kV transformation into Las Cruces. Therefore, it is unlikely that the power could be sold using this path, unless this power were used in lieu of other imports. The extent of the problem and the ultimate relevance for a 50 MW parabolic trough plant cannot be fully assessed until a new transmission study is performed by the transmission-owning entities in the region.

8.3 Scenario 3: Central Trough Utility Purchase

- Electricity Cost: \$94.50 - 129.50/MWh.
- Capital Investment: \$239 - \$289 million.

Albuquerque is the largest in-state market for solar power, and the existing body of transmission studies indicates that there is enough available transmission capacity to readily accommodate output from a new 50 MW solar power plant. Parabolic troughs have a 15 year history of commercial operation and provide the lowest COE for an acceptable level of risk. The utility purchase strategy is an attractive development approach because of the low cost of debt and favorable equity terms provided by utilities. It is estimated that with highly favorable incentives, a 50 MW trough with wet cooling located in central New Mexico would have a first-year COE of \$94.50/MWh under this development scenario. The primary challenges associated with this development scenario

include the difficulty of obtaining water rights in the region and the potential unwillingness of utilities to own and operate a large-scale solar power plant.

8.3.1 Action Items

Increased state incentives would be needed to reduce the cost and increase the financial attractiveness of the 50 MW parabolic trough plant. To advance this development scenario, state policy makers should focus on increasing state incentives relative to the current policy environment. The refundable 10 year, 2 cents/kWh PTC represents the highest value incentive. Enactment of this incentive should take precedence over other action items. A GRT exemption, a property tax exemption, and a partial performance guarantee would also improve the financial attractiveness of a prospective solar power plant and should also be pursued.

The formation of a consortium of utilities with a willingness to invest in the development of one or more large-scale solar power plants is an important action item that must be pursued to advance this development scenario. Within New Mexico, utilities may have an interest in solar power in the context of the state RPS, which provides triple compliance credit for solar power. However, given least-cost power procurement approaches of these entities, a New Mexico-only utility consortium may be difficult to assemble. It may be necessary to seek the participation of regional utilities that have an interest in large-scale solar power because of state-specific RPS programs or to satisfy other objectives. Ultimately, it may be necessary to look beyond New Mexico's borders and seek greater participation to advance the development of large-scale solar power within the context of any conceivable development strategy. Ultimately, New Mexico may not have the appropriate level of energy demand, transmission capability, and long-term utility support required to advance the development of one or more large-scale solar power plants.

8.3.2 Location

Central New Mexico, which has been identified as Location 1 within the context of this study, has only a slightly less favorable solar resource than southwest New Mexico and is the ideal location for a solar power visitor's center. The DNI solar resource for this location is estimated to be 7.21 kWh/m²/day. It has been modeled as the TMY2 data for El Paso, scaled proportionately to the satellite data for Location 2.

It is estimated that with highly favorable incentives, a 50 MW trough with wet cooling located in Location 1 under the utility purchase development approach has a first-year COE of \$94.50/MWh, compared to a first-year COE of \$88.90/MWh at Location 2

in southwest New Mexico.² The increase of \$5.60/MWh is due entirely to the less favorable solar sources in central New Mexico. Three sites have been identified within Location 1: Site 5, 2 miles west of Belen; and Site 7, 10 miles southeast of Belen.

8.3.3 Technology

Development of a parabolic trough plant with 6 hours of thermal storage and with dry or wet cooling, depending upon the need for reduced water consumption, is recommended. Parabolic troughs have a 15 year history of commercial operation and provide the lowest first-year COE and a level of risk that falls within the tolerance of the financial markets, as long as commonly accepted risk reduction strategies are employed. Thermal storage would enable a plant to provide guaranteed capacity and to shift energy production to the highest value periods.

8.3.4 Financial Analysis

Table 8-6 shows the cost, revenue, performance, and water consumption estimates for four configurations of 50 MW parabolic trough plants located in central New Mexico.

The plant with 6 hours of thermal storage is recommended because of the reduced first-year COE and higher expected revenues. The cooling technology selection is a function of the value of reduced water consumption. It is estimated that the parabolic trough with 6 hours' storage and wet cooling would consume approximately 610,000 gallons per year. It is estimated that the same plant with wet cooling would consume approximately 48,000 gallons per year. Since the first-year energy production costs with wet and dry cooling are estimated at \$94.50/MWh and \$97.20/MWh, respectively, 562,000 gallons of water consumption per year could be avoided for an increased production cost of \$2.70/MWh. It should be noted that given the difficulty of obtaining water rights in the region, dry cooling may be the only feasible approach to project development in central New Mexico.

² Throughout this study, it was assumed that the solar plant would become operational in 2007 and that the COE would escalate at 2 percent per year thereafter.

Table 8-6
Central 50 MW Parabolic Trough Cost, Revenue, and Performance Estimates

Technology	Thermal Storage (hours)	Cooling Technology	Capital Cost (\$/kW)	O&M (\$/MWh)	Energy Production (Thousand MWh)	Water Consumption (Thousand Gallons)	Average Annual Revenue (\$/kW/year)	First-Year COE w/Full Incentives* (\$)
Parabolic Trough	0	Wet	3,950	33	105 (24.6%)	421	84	102.70
Parabolic Trough	3	Wet	4,820	30	130 (29.6%)	507	104	100.30
Parabolic Trough	6	Wet	5,600	27	156 (35.6%)	610	121	94.50
Parabolic Trough	6	Dry	5,660	39	155 (35.5%)	48	120	97.20

*Under a utility purchase development scenario assuming 30 year debt at 5 percent. Incentive package includes a 2 cents/kWh state PTC, a performance guarantee, a property tax exemption, and a GRT exemption in addition to existing incentives.

8.3.5 Market

The preferred option is to deliver power to the nearest wholesale customer, which, in this case, means delivery to the Albuquerque load center. A second less favorable option would be to transmit energy south to Las Cruces/El Paso. Power could be delivered to the El Paso control area at the West Mesa 345 kV substation and then delivered south on El Paso's West Mesa-Arroyo 345 kV line. However, the feasibility of this option must be studied because existing evidence indicates that this transfer would involve a change that could adversely affect the transfer capacity of northern New Mexico.

A third option would be to transmit energy to the Four Corners area for delivery west or to the Colorado Front Range. Unfortunately, transmission delivery from the Four Corners area is problematic because there is little or no long-term firm transmission service available. Deliveries to the Colorado Front Range would be expected to have similar limitations due to a west-to-east transmission constraint in central Colorado.

Emerging voluntary and compliance REC markets throughout the western United States have the potential to provide an additional revenue source for the non-energy attributes of solar plant output. However, these markets are not yet well defined and are generally illiquid. As a result, it is unlikely that REC revenue could be used to attract financing.¹

Regardless of the ultimate market for solar power, the expected revenue from energy sales would be far short of the required revenue. It is estimated that an annual payment in the range of \$250 to \$300/kW would be required to cover operating expenses, service debt, pay taxes, and provide a return to equity investors. Energy sales would account for approximately 50 percent of this revenue, even in the most optimistic scenario.

8.3.6 Development Approach

The utility purchase strategy is an attractive development approach because of the low cost of debt and favorable debt terms offered by publicly owned utilities. Under this approach, the solar plant would be fully developed by an independent power producer and then sold directly to one or more New Mexico utilities for the cost of construction, plus a 6 percent development fee. The utility consortium would be expected to finance the purchase using a 50:50 debt-to-equity capital structure. The debt terms would vary,

¹ Refer to Draker, et al. (2004) "Markets for Bulk Solar Power: Issues and Opportunities Associated With Serving Markets Outside of New Mexico With New Mexico Solar Power," Center for Resource Solutions, San Francisco, CA, November, 2004; and Draker, et al. (2004) "New Mexico Concentrating Solar Power Feasibility Study: Issues and Opportunities Associated With the Use of Renewable Energy Certificates As An Energy Marketplace Currency," Center for Resource Solutions, San Francisco, CA, November 2004.

but debt terms could be as favorable as 30 year debt with a 5.7 percent interest rate. Equity terms would vary, but equity terms could be as favorable as a 12 percent expected rate of return.

8.3.7 Incentives

Under this development scenario, favorable state and federal incentives would be required to move the COE toward a competitive level. Clearly, greater levels of public assistance would alleviate the financial burden of the plant owner and/or power purchaser. Under the current policy environment, it is estimated that a 50 MW trough with wet cooling located in Location 1 would have a COE of \$129.50/MWh. If the 10 year state PTC is increased to 2 cents/kWh, then the COE would fall to \$117.60/MWh. Under a highly favorable policy package that includes the 2 cents/kWh PTC, a state GRT, a property tax exemption, and a state-sponsored partial performance guarantee that reduces risk to the EPC contractor, the COE would drop to \$94.50/MWh. Table 8-7 shows the impact of each incentive option.

Table 8-7 Incentive Options for Central 50 MW Parabolic Trough with 6 Hours Storage and Wet Cooling*			
Incentive	First-Year COE (\$/MWh)	Difference From Current Policy Environment (\$/MWh)	Cost to Government (Million \$)
Current Policies	129.50		\$15.6 over 10 years.
2 cents/kWh Refundable State PTC	117.60	11.90	\$31.20 over 10 years.
Performance Guarantee	114.50	15.00	No cost if plant performs as expected.
GRT Exemption	121.00	8.50	No cost if plant is not constructed because there are no incentives.
Property Tax Exemption	119.90	9.60	No cost if plant is not constructed because there are no incentives.
All Incentives	94.50	35.00	\$31.20 over 10 years for 2 cents/kWh PTC.
*Under a utility purchase development scenario assuming 30 year debt at 5 percent.			

8.3.8 Benefits

A recent, companion study by the UNM BBER indicates that development of a 50 MW solar power plant would result in the creation of between 925 and 1,222 construction jobs and would inject between \$225 and \$250 million into the state economy.² Ongoing plant operations would yield 74 new jobs and would inject \$7.5 million into the state economy annually (or \$225 million over the 30 year life of the plant.) Taken together, this means that a 50 MW parabolic trough would be expected to inject at least \$450 million into the state economy over its lifetime. Further, BBER estimates that a 50 MW parabolic trough plant would have a net positive fiscal impact of between \$104 and \$110 million over the life of the plant.

If the plant performs as expected, then the cost of the state PTC would represent the only direct costs to the state for the development of a 50 MW parabolic trough plant. If the PTC were to be increased to 2 cents/kWh as currently proposed, then the PTC cost would total \$31 million over the 10 year PTC eligibility period. Thus, for \$31 million in lost tax revenue over a 10 year period, a 50 MW parabolic trough plant would inject \$450 million into the state economy while yielding a positive fiscal impact of at least \$104 million. It should be noted that this analysis excludes the positive benefits associated with decreased reliance on volatile natural gas and the environmental advantages of reduced local air pollutants and greenhouse gas emissions; it also excludes the economic costs associated the reduced competitiveness of New Mexico businesses as a result of solar power purchases.

8.3.9 Barriers

Utilities generally favor least-cost supply options in lieu of more expensive renewable power options. Solar power options may be viewed unfavorably by these load-serving entities because of the higher cost of solar power relative to other alternatives such as wind, biomass, and geothermal. Against this backdrop, finding a utility willing to purchase and operate a 50 MW solar power plant will be challenging. The most attractive option may be to assemble a consortium of utilities to share the costs and risks associated with the 50 MW parabolic trough. There is potential for the development of a consortium of utilities throughout central New Mexico that would be interested in the development of large-scale solar power for both voluntary and RPS compliance purposes. Finally, water rights are an issue. Given the difficulty of obtaining

² Bureau of Business and Economic Research (2004), "The Economic Impact of Concentrating Solar Power in New Mexico," University of New Mexico Bureau of Business and Economic Research (BBER), Albuquerque, NM, November 2004.

water rights in the region, dry cooling may be the only feasible approach to project development in central New Mexico.

8.4 Scenario 4: Central Trough Private Ownership

- Electricity Cost: \$99.80 - \$191.30/MWh.
- Capital Investment: \$239 - \$289 million.

Albuquerque is the largest in-state market for solar power, and the existing body of transmission studies indicates that there is enough available transmission capacity to readily accommodate output from a new 50 MW solar power plant. Parabolic troughs have a 15 year history of commercial operation and provide the lowest COE for an acceptable level of risk. The private ownership strategy may be a viable development approach with the assistance of state entities such as the NMFA and the SIC, which may be able to provide debt or equity capital at favorable terms. It is estimated that with highly favorable incentives, a 50 MW trough with wet cooling located in central New Mexico would have a COE of \$116.90 MWh under this development scenario assuming 20 year debt at 7 percent. Some of the primary challenges associated with this development scenario include acquiring water rights in the region and the ability to raise sufficient debt and equity capital to fund project construction.

8.4.1 Action Items

Increased state incentives would be required to reduce the cost and increase the financial attractiveness of the 50 MW parabolic trough plant. To advance this development scenario, state policy makers should focus on increasing state incentives relative to the current policy environment. The refundable 10 year 2 cents/kWh production tax credit represents the highest value incentive. Enactment of this incentive should take precedence over other action items. A GRT exemption, a property tax exemption, and a partial performance guarantee would also improve the financial attractiveness of a prospective solar power plant and should also be pursued.

In addition to the promotion of state incentives, additional state-level legislative changes could be useful in promoting a large-scale solar project in New Mexico. In particular, it might be necessary to increase the \$20 million per project cap that the SIC currently faces when purchasing investment-grade bonds. Further, raising the 10 percent limit in SIC's Private Equity Investment Program (which effectively places a \$20 million per project cap on equity contributions) would open up additional equity capital to support this project. Finally, an appropriation on the order of \$50 million or more would provide the conditions under which the SWEDFA could be used to support the development of a new large-scale solar power project in New Mexico.

8.4.2 Location

Central New Mexico, which has been identified as Location 1 within the context of this study, has only a slightly less favorable solar resource than the Southwest Location, and is the ideal location for a solar power visitor's center. The DNI solar resource for this location is estimated to be 7.21 kWh/m²/day. It has been modeled as the TMY2 data for Albuquerque scaled proportionately to the satellite data for Location 1.

It is estimated that with highly favorable incentives, a 50 MW trough with wet cooling located in Location 1 under the private ownership development approach (assuming 20 year debt at 7 percent) would have a first-year COE of \$116.90/MWh, compared to a first-year COE of \$109.90/MWh at Location 2 in southwest New Mexico under the same assumptions.³ The increase of \$7.00/MWh is due entirely to the less favorable solar sources in central New Mexico. Three sites have been identified within Location 1: Site 5, 2 miles west of Belen; and Site 7, 10 miles southeast of Belen.

8.4.3 Technology

It is recommended that a parabolic trough plant with 6 hours of thermal storage and with dry or wet cooling, depending upon the need for reduced water consumption, be developed. Parabolic troughs have a 15 year history of commercial operation and provide the lowest first-year COE and a level of risk that falls within the tolerance of the financial markets as long as commonly accepted risk reduction strategies are employed. Thermal storage would enable a plant to provide guaranteed capacity and to shift energy production to the highest value periods.

8.4.4 Financial Analysis

Table 8-8 shows the cost, revenue, performance, and water consumption estimates for four configurations of 50 MW parabolic trough plants located in central New Mexico.

The plant with 6 hours of thermal storage is recommended because of the reduced first-year COE and higher expected revenues. The cooling technology selection is a function of the value of reduced water consumption. It is estimated that the parabolic trough with 6 hours' storage and wet cooling would consume approximately 610,000 gallons per year. It is estimated that the same plant with wet cooling would consume

³ Throughout this study, it was assumed that the solar plant would become operational in 2007 and that the COE would escalate at 2 percent per year thereafter.

Table 8-8
Central 50 MW Parabolic Trough Cost, Revenue, and Performance Estimates

Technology	Thermal Storage (hours)	Cooling Technology	Capital Cost (\$/kW)	O&M (\$/MWh)	Energy Production (Thousand MWh)	Water Consumption (Thousand Gallons)	Average Annual Revenue (\$/kW/year)	First-Year COE w/Full Incentives* (\$)
Parabolic Trough	0	Wet	3,950	33	105 (24.6%)	421	84	125.60
Parabolic Trough	3	Wet	4,820	30	130 (29.6%)	507	104	123.50
Parabolic Trough	6	Wet	5,600	27	156 (35.6%)	610	121	109.90
Parabolic Trough	6	Dry	5,660	39	155 (35.5%)	48	120	113.90

*Under a private ownership development scenario assuming 20 year debt at 7 percent. Incentive package includes a 2 cents/kWh state PTC, a performance guarantee, a property tax exemption, and a GRT exemption in addition to existing incentives.

approximately 48,000 gallons per year. Since the first-year energy production costs with wet and dry cooling are estimated at \$109.90/MWh and \$113.90/MWh, respectively, 562,000 gallons of water consumption per year could be avoided for an increased production cost of \$4.00/MWh. It should be noted that given the difficulty of obtaining water rights in the region, dry cooling may be the only feasible approach to project development in the Southwest.

8.4.5 Market

The preferred option is to deliver power to the nearest wholesale customer, which, in this case, means delivery to the Albuquerque load center. A second less favorable option would be to transmit energy south to Las Cruces/El Paso. Power could be delivered to the El Paso control area at the West Mesa 345 kV substation and then delivered south on El Paso's West Mesa-Arroyo 345 kV line. However, the feasibility of this option must be studied because existing evidence indicates that this transfer would involve a change that could adversely affect the transfer capacity of northern New Mexico.

A third option would be to transmit energy to the Four Corners area for delivery west or to the Colorado Front Range. Unfortunately, transmission delivery from the Four Corners area is problematic because there is little or no long-term firm transmission service available. Deliveries to the Colorado Front Range would be expected to have similar limitations due to a west-to-east transmission constraint in central Colorado.

Emerging voluntary and compliance REC markets through the western United States have the potential to provide an additional revenue source for the non-energy attributes of solar plant output. However, these markets are not yet well defined and are generally illiquid. As a result, it is unlikely that REC revenue could be used to attract financing.¹

Regardless of the ultimate market for solar power, the expected revenue from energy sales would be far short of the required revenue. It is estimated that an annual payment in the range of \$250 to \$300/kW would be required to cover operating expenses, service debt, pay taxes, and provide a return to equity investors. Energy sales would account for approximately 50 percent of this revenue, even in the most optimistic scenario.

¹ Refer to Draker, et al. (2004) "Markets for Bulk Solar Power: Issues and Opportunities Associated With Serving Markets Outside of New Mexico With New Mexico Solar Power," Center for Resource Solutions, San Francisco, CA, November, 2004; and Draker, et al. (2004) "New Mexico Concentrating Solar Power Feasibility Study: Issues and Opportunities Associated With the Use of Renewable Energy Certificates As An Energy Marketplace Currency," Center for Resource Solutions, San Francisco, CA, November 2004.

8.4.6 Development Approach

The private ownership strategy may be a viable development approach with the assistance of state entities such as the NMFA and the SIC, which may be able to provide debt or equity capital at favorable terms. Under this approach, the project would be developed by a private sector developer who would fund the development cost. The project would be financed with a combination of equity and debt. Debt could be sourced from (1) a commercial bank, (2) a taxable bond issuance, or (3) a public entity such as the federal or state government. A variation of these debt options is to “credit enhance” the debt through a letter of credit. The equity would be raised from private sector investors who have a need for the tax benefits from the project.

8.4.7 Debt

Debt terms would vary by source. A commercial bank would be expected to provide 14 year debt with a 6.2 percent interest rate. If debt is raised through a private taxable-bond issuance, then the debt term may be as long as 20 years with an interest rate of 7 percent. Along with financial market participants, the State of New Mexico is a prospective buyer through such a bond issuance, since the SIC is authorized to purchase investment-grade bonds up to a \$20 million cap per project. This cap can be increased to \$50 for AAA bonds. This raises the intriguing possibility that a solar project could achieve a AAA credit rating by purchasing insurance against loan default. The merits of this possibility will depend upon the cost of insurance relative to the value of an enhanced credit rating.

8.4.8 Equity

Equity terms would be expected to be in accordance with market rates. Analysis indicates that 15 percent represents the minimum 15 year hurdle rate for a large-scale solar project. It is acknowledged that this hurdle rate may represent the low side, given the perceived risks associated with the development of a new large-scale solar power project. Again here, on the equity side, the State of New Mexico, may have an opportunity to play a role in buttressing private equity dollars with additional public-sector funds. Through the New Mexico Private Equity Investment program, the SIO may invest in private equity funds (upon approval of the Private Equity Investment Advisory Council and the SIC). This means that the state could take an equity position in a prospective new large-scale solar power project located in New Mexico. However, the state investment may represent no more than 51 percent of the equity in a particular project and only 10 percent of the total money available for this state investment program (approximately \$20 million) may be invested in any one company. It is estimated that

this 10 percent limit may have to be increased to at least 25 percent to provide a level of equity that would facilitate the development of a new large-scale solar power project in New Mexico.

Finally, it should be noted that the NMFA has a wide range of financial assistance options under New Mexico's SWEDFA, which was passed in 2004. Through SWEDFA, NMFA has the ability to provide debt or equity to a new large-scale solar power project in New Mexico that promotes statewide economic development. SWEDFA also provides NMFA with the ability to provide other forms of financial assistance such as grants and loan guarantees. However, funds have yet to be appropriated to support SWEDFA. It is expected that funds will be appropriated during the 2005 legislative session. It is believed that an appropriate level of \$50 million or more would be required to provide the conditions under which SWEDFA could be used to support the development of a new large-scale solar power project in New Mexico.

Table 8-9 shows the first-year COE for a 50 MW parabolic trough with 6 hours of storage and wet cooling located in central New Mexico under the private ownership development approach for two different debt-equity funding source combinations. The obvious conclusion from Table 8-9 is that developers should seek long-term debt at the lowest possible interest rate. Because solar power projects are extremely capital intensive, debt financing terms are the single largest factor in determining a solar plant's cost of production.

Table 8-9 First-Year COE for a Central 50 MW Parabolic Trough with 6 Hours Storage and Wet Cooling			
Debt	Equity	Capital Structure (Debt:Equity)	First-Year COE With Full Incentives (\$/MWh)
Commercial bank debt with a 14 year term at 6.2 percent	Strategic and/or passive tax investor(s) with a 15 percent hurdle rate.	50:50	130.40
Private taxable bond issuance with a 20 year term at 7 percent	Strategic and/or passive tax investor(s) with a 15 percent hurdle rate.	50:50	116.90

8.4.9 Incentives

Under this development scenario, favorable state and federal incentives would be required to move the COE toward a competitive level. Clearly, greater levels of public assistance would alleviate the financial burden of the plant owner and/or power

purchaser. Under the current policy environment, it is estimated that a 50 MW trough with wet cooling located in Location 1 would have a first-year COE of \$168.40/MWh. If the 10 year state PTC is increased to 2 cents/kWh, then the first-year COE would fall to \$144.70/MWh. Under a highly favorable policy package that includes the 2 cents/kWh PTC, a state GRT, a property tax exemption, and a state-sponsored partial performance guarantee that reduces risk to the EPC contractor, the first-year COE would drop to \$116.90/MWh. Table 8-10 shows the impact of each incentive option.

Table 8-10 Incentive Options for Central 50 MW Parabolic Trough with 6 Hours Storage and Wet Cooling*			
Incentive	First-Year COE (\$/MWh)	Difference From Current Policy Environment (\$/MWh)	Cost to Government (Million \$)
Current Policies	168.40		\$15.6 over 10 years.
2 cents/kWh Refundable State PTC	144.70	23.68	\$31.20 over 10 years.
Performance Guarantee	148.50	19.88	No cost if plant performs as expected.
GRT Exemption	157.50	10.88	No cost if plant is not constructed because there are no incentives.
Property Tax Exemption	158.70	9.68	No cost if plant is not constructed because there are no incentives.
All Incentives	116.90	51.48	\$31.20 over 10 years for 2 cents/kWh PTC.
*Under a private taxable bond issuance scenario assuming 20 year debt at 7 percent.			

8.4.10 Benefits

A recent, companion study by the UNM BBER indicates that development of a 50 MW solar power plant would result in the creation of between 925 and 1,222 construction jobs and would inject between \$225 and \$250 million into the state economy.² Ongoing plant operations would yield 74 new jobs and would inject \$7.5 million into the state economy annually (or \$225 million over the 30 year life of the

² Bureau of Business and Economic Research (2004), "The Economic Impact of Concentrating Solar Power in New Mexico," University of New Mexico Bureau of Business and Economic Research (BBER), Albuquerque, NM, November 2004.

plant.) Taken together, this means that a 50 MW parabolic trough would be expected to inject at least \$450 million into the state economy over its lifetime. Further, BBER estimates that a 50 MW parabolic trough plant would have a net positive fiscal impact of \$104 and \$110 million over the life of the plant.

If the plant performs as expected, then the cost of the state PTC would represent the only direct costs to the state for the development of a 50 MW parabolic trough plant. If the PTC is increased to 2 cents/kWh as currently proposed, then the PTC cost would total \$31 million over the 10 year PTC eligibility period. Thus, for \$31 million in lost tax revenue over a 10 year period, a 50 MW parabolic trough plant would inject \$450 million into the state economy while yielding a positive fiscal impact of at least \$104 million. It should be noted that this analysis excludes the positive benefits associated with decreased reliance on volatile natural gas and the environmental advantages of reduced local air pollutants and greenhouse gas emissions; it also excludes the economic costs associated the reduced competitiveness of New Mexico businesses as a result of solar power purchases.

8.4.11 Barriers

Between \$239 and \$289 million in equity and debt capital would be required to develop a new 50 MW parabolic trough plant in central New Mexico. Raising this level of capital would be a formidable task, particularly in light of the limited familiarity that capital markets have with large-scale solar power technologies. Although parabolic trough plants have a track record of commercial success, limited development over the last 15 years has increased the perceived risk associated with the technology. As a result, debt funding may be difficult to obtain, particularly through traditional lending sources such as commercial banks. On the equity side, there is a limited pool of developers who have the ability to assume a substantial equity stake in a new project. Further, these developers generally do not have the tax base necessary to take full advantage of the federal and state tax benefits available to solar power project owners. Finally, water rights are an issue. Given the difficulty of obtaining water rights in the region, dry cooling may be the only feasible approach to project development in Central New Mexico.

8.5 Scenario 5: Demonstration Project

- Capital Investment: \$82 - \$97 million.

In lieu of a 50 MW parabolic trough project with a required capital investment in the range of \$250 million, a smaller scale and lower cost demonstration project could be developed to advance the state of knowledge on a pre-commercial CSP technology.

Whereas parabolic troughs have a 15 year history of successful commercial operation and provide the lowest COE, dish-Stirling and power tower systems, which have advantages over parabolic troughs such as the increased modularity provided by dish-Stirling systems and inherent thermal storage of the power tower, do not have extensive commercial operating experience. Experience obtained through a demonstration project would increase available technological knowledge about parabolic troughs, leading to a reduction in costs and a reduction in real and imagined technology risks that will increase the probability of successful commercialization of these technologies in the next decade. A public ownership strategy is the most likely development approach for this demonstration project. The State of New Mexico may opt to purchase the project outright for an estimated cost of \$82 to \$97 million, or engage in negotiations with a consortium of New Mexico utilities to provide joint funding.

8.5.1 Action Items

The first action item will be to engage in discussion with non-parabolic trough CSP technology manufacturers regarding the most favorable demonstration technologies. These discussions should involve the New Mexico Concentrating Solar Power Task Force, and the ultimate technology selection should be a reflection of the underlying objective to advance the state of technology knowledge to accelerate the commercial deployment of CSP demonstration systems. It may be necessary to fund a demonstration project feasibility study to ensure that all options are properly considered. Another action item will be to determine the magnitude of the capital investment required and grants needed and to identify possible sources. Consideration should be given to the possibility of developing a utility consortium or CSP industry consortium to assist in the financing and construction of the demonstration project. Technology manufacturers should be contacted regarding a possible joint venture.

8.5.2 Location

Central New Mexico, which has been identified as Location 1 within the context of this study, has slightly lower solar resources than southwest New Mexico, but is well-suited for a demonstration plant because of its proximity to Albuquerque. The DNI solar resource for this location is estimated to be 7.21 kWh/m²/day. It has been modeled as the TMY2 data for Albuquerque scaled proportionately to the satellite data for Location 1.

8.5.3 Technology

The technical characteristics of both a single 14 MW power tower plant with 6 hours of thermal and a cluster of 560 25 kW dish-Stirling units have been examined. Both technologies have significant technical merits. Power towers offer a strong thermal storage capability to shift energy production to the highest value periods. Dish-Stirling units provide the inherent benefits of modularity and dry cooling. However, it was concluded that neither system is suitable for commercial development by 2007. As such, both technologies were classified as pre-commercial demonstration systems. It should be noted that a 150 kW prototype dish-Stirling system located at SNL in Albuquerque will begin operation in 2005. Power towers have previously been operated in a 10 MW demonstration system in California.

8.5.4 Financial Analysis

To compare this project to the other scenarios, calculations were performed on the hypothetical cost of a system of 560, 25 kW dish-Stirling units and a single 14 MW power tower system under the most favorable utility purchase development strategy with a complete policy package. Under this development approach, the first-year COE for the dish-Stirling and power tower systems would be \$147/MWh and \$161/MWh, respectively. For reference, the first-year COE for a 50 MW parabolic trough plant with wet cooling and 6 hours of storage located in central New Mexico is \$94.50/MWh.

8.5.5 Development Approach

Whereas parabolic troughs have a 15 year history of successful commercial operation and provide the lowest COE, dish-Stirling and power tower systems, which have advantages over parabolic troughs such as the increased modularity provided by dish-Stirling systems, do not have extensive commercial operating experience. A public ownership strategy is the most likely development approach for this demonstration project. The State of New Mexico may opt to purchase the project outright for an estimated cost of \$82 to \$97 million, or engage in negotiations with a consortium of New Mexico utilities to provide joint funding.

8.5.6 Benefits

Experience obtained through a demonstration project would reduce the available technological knowledge about parabolic troughs, leading to a reduction in costs and a reduction in real and imagined technology risks that will increase the probability of successful commercialization of these technologies in the next decade. There may be an additional benefit to the state with respect to technology development, particularly if

there were requirements or agreements associated with grant funding that resulted in locating the solar system component manufacturing within New Mexico. In addition, development of a CSP demonstration project would place New Mexico in a leadership position for an emerging renewable power technology. The presence of this demonstration, along with world-class facilities and capabilities at SNL would place the state in a leadership position that might ultimately attract solar power manufacturing facilities.

9.0 Conclusions

9.1 Technology

Parabolic trough technology was deemed to be the only CSP technology ready for a commercial project by 2007. While both 50 MW and 100 MW trough plants were characterized, financial evaluations focused on several 50 MW trough system configurations.

- No storage, with wet cooling.
- Three hours storage, with wet cooling.
- Six hours storage, with wet cooling.
- Hybrid solar/fossil, with wet cooling.
- Six hours storage, with dry cooling.

The lowest cost of energy system, as well as the system best matching the PNM load curve, has six hours of storage. Dry cooling greatly reduces water usage, with somewhat higher capital cost and cost of energy.

Although power tower, dish-Stirling, and high concentration PV technologies have distinct capabilities and significant potential, they were deemed to be in the pre-commercial stage and therefore unable to meet the requirement of a 50 MW or larger commercially operating plant by 2007. The nontrough technologies are currently more suitable for demonstrations in the 10 to 15 MW size.

9.2 Site Options

Two general regions of the state were identified as preferred locations in New Mexico. Location 1 is in the central portion of the state, in the vicinity of Albuquerque. Two sites were identified in this area, one 10 miles southeast of Belen and the other 2 miles west of Belen. Location 2 is in the southwestern portion of the state where three sites were identified. One site is immediately northwest of Deming; a second site is immediately northeast of Lordsburg; a third site is 12 miles southeast of Lordsburg. Because the solar energy intensity is somewhat higher in the southwest location, the cost of electricity from a CSP plant of any configuration will be about 1 cent/kWh lower there than for a similar plant located in the central location. Water availability is more likely to be problematic in central New Mexico sites than in southwest sites.

9.3 Incentives

The most direct way to support a CSP plant is with a power purchase agreement (PPA) that provides sufficient revenue to cover all costs, service the debt and provides an

acceptable rate of return to project sponsors. Because of the high up-front capital costs of CSP projects, incentives and programs that increase the term of the debt and/or reduce the interest rate can reduce CSP project costs significantly.

The effectiveness of any particular incentive in improving the cost competitiveness of a CSP plant depends upon a variety of project-specific technical and financial factors including plant energy production level, debt terms, the amount of leverage, and the tax rate and liability of equity participants. For example, under current policies, we estimate that the cost of electricity for a privately-owned 50 MW parabolic trough plant financed with commercial bank debt and located in southwestern New Mexico is \$179/MWh. Our calculations indicate that a property tax exemption would reduce this cost by \$10/MWh, a gross receipts tax (GRT) exemption would reduce the cost by \$12/MWh, a state-sponsored partial performance guarantee would reduce the cost by \$22/MWh, a 2¢/kWh (\$20/MWh) state production tax credit (PTC), would reduce the cost by \$25/MWh, and all of these incentives combined would drop the cost by \$56/MWh.

9.4 Market Access

A 50 MW CSP plant located at one of the sites in central New Mexico would be able to serve the Albuquerque load center without the need for additional transmission investments. A 50 MW CSP plant in the central location could also transmit power to northwest New Mexico to the Four Corners region. However, access to markets beyond the Four Corners are likely to be problematic because of transmission bottlenecks heading west into Arizona, California and Nevada. Furthermore, west-to-east transmission constraints may limit power flows into Colorado's Front Range.

The transmission situation appears to be even more challenging in southwest New Mexico. A transmission study must be conducted to determine if a 50 MW CSP plant located in one of the sites identified in southwest New Mexico could successfully transmit power to the combined Las Cruces/El Paso load center. Further, additional study is needed to determine if a 50 MW CSP plant could transmit power to Albuquerque. It appears, however, that short-term transmission capacity is available to transmit power into Arizona. It is considered that the most likely scenario would be for the CSP plant to transmit power to the nearest in-state customer.

9.5 Ownership Models

Two CSP project ownership options were modeled by the Black & Veatch team: a utility ownership case in which a private entity develops the power plant and then sells it to a utility, which subsequently owns and operates the facility, and a private ownership

case, in which the plant is developed and operated by a private entity that finances project construction with a combination of equity and debt from a commercial bank, development bank, or taxable bond issuance.

9.6 Development Pathways

Four scenarios for 50 MW trough plants were evaluated to identify the promising pathways for the development of a commercially operating CSP plant by 2007:

- Utility-owned 50 MW parabolic trough plant in southwest New Mexico.
- Privately-owned 50 MW parabolic trough plant in southwest New Mexico.
- Utility-owned 50 MW parabolic trough plant in central New Mexico.
- Privately-owned 50 MW parabolic trough plant in central New Mexico.

With a full set of incentive options that includes a 2 cent/kWh state production tax credit, a property tax exemption, a gross receipts tax exemption, and a state-sponsored partial performance guarantee, the cost of electricity for a 2007 plant would range from \$89 to \$117/MWh. Although this is a very attractive cost for solar power, it is nearly double the current wholesale price of electricity. As a result, even in the presence of attractive incentives for CSP development, New Mexico load serving entities would be obligated to purchase CSP output at an above-market rate to induce the commercial development of a CSP plant in New Mexico by 2007.

In addition to these four commercial development pathways, the benefits of a state-sponsored CSP demonstration program involving one or more of the non-trough pre-commercial CSP technologies were evaluated. In lieu of commercial financing, joint federal-state public funding, or private funding from a consortium of utilities would be required to embark upon a CSP demonstration project that would seek to advance the state of technical knowledge and operating experience for non-commercial CSP technologies.

9.7 Benefits to New Mexico

A companion study by BBER evaluated the economic impact on the state of building a single 50 MW CSP plant, a single 100 MW CSP plant, or five 100 MW CSP plants over a 10 year period. Their results showed that if a 50 MW CSP plant were to be built in New Mexico, the state's tax revenue, after any additional state expenses are subtracted, would increase by a total of \$104 million over the 30 year life of the plant. In addition, the state's economy would gain almost \$500 million over that same period and about 1,000 temporary construction jobs and 74 permanent plant operation jobs would be created. If the state were to provide the full set of state incentives, the cost to the state's treasury would be about \$33 million, leaving a net \$70 million.

The benefits to New Mexico from either a dish-Stirling or power tower demonstration are technology leadership and positioning the state to attract relevant manufacturing facilities to the state.

Appendix A
**Preliminary Permitting Requirements for a Solar Electrical
Generation Facility with Natural Gas-Fired Backup**

Agency	Permit/ Approval	Regulated Activity	Required Project Phase	Expected Review Time	Applicable to Project	Comments/Issues
FEDERAL						
BLM	Right-of-Way Grant	Authorization to cross public land (project related road, t-line, or pipeline).	Construction	Minimum time frame to process grant is 60 - 90 days. For larger projects, up to 18 - 24 months may be required, especially if an EIS is required.	MAYBE	ROW grant will require a number of environmental surveys, cultural resource survey, and possibly NEPA EIS.
BLM	Temporary Use Permit (TUP)	Laydown area during construction.	Construction	May be processed with ROW grant, or separately.	NO	TUP may be granted for up to 3 years. Assume project will not need additional area for construction laydown.
COE	Section 10 Permit	Construction activities in navigable water of the US.	Construction	3 - 4 months for nationwide permit, 12 - 18 months for individual permit.	MAYBE	Required for construction of intake or outfall structure in navigable waters of US, or crossing navigable waters with t- line, pipeline, or project related road. Nationwide permit may be available.
COE	Section 404 Permit	Discharge of dredge or fill material into US waters, including jurisdictional wetlands.	Construction	3 - 4 months for nationwide permit, 12 - 18 months for individual permit.	MAYBE	Required if wetlands will be filled on site or along off-site utility right-of-way. Nationwide permit(s) may be available.
EPA	NPDES General Permit for Storm Water Discharges from Construction Sites	Discharge of storm waters from construction sites of 1 acre or more.	Construction	Submit NOI 48 hours before activity.	YES	New Mexico does not yet have primacy of the NPDES program; NPDES permits will be issued by the EPA. The general permit requires a SWPPP be prepared and implemented prior to project construction.

Agency	Permit/ Approval	Regulated Activity	Required Project Phase	Expected Review Time	Applicable to Project	Comments/Issues
EPA	NPDES Multi-Sector General Permit (Storm water) for Industrial Activities	Discharge of storm waters during facility operation.	Operation	Submit NOI 48 hours before activity.	MAYBE	New Mexico does not yet have primacy of the NPDES program; NPDES permits will be issued by the EPA. If the project does not qualify for a general storm water permit, an individual storm water permit will be required. The general permit requires a SWPPP be prepared and implemented prior to project operation.
EPA	NPDES Individual Permit for Wastewater/Storm Water Discharges	Discharge of industrial wastewaters, including storm water runoff, during facility operation.	Operation	Application must be submitted to the EPA at least 180 days prior to discharge.	YES	New Mexico does not yet have primacy of the NPDES program; NPDES permits will be issued by the EPA. The project may qualify for a storm water general permit.
EPA	SPCC Plan	Onsite storage oil storage tanks with combined capacity of >1,320 gallons. Tanks < 55 gallons are exempt from SPCC requirements.	Construction/ Operation	Plan is not reviewed, but must be available at facility upon request, by agency.	YES	Required for oil storage. Consider all oil products - fuel oil, transformer oil, equipment lube oils, waste oils, etc, for entire site. Plan must be prepared within 6 months of commencement of commercial operation.
EPA	Facility Response Plan	May be required for onsite storage of 1 million gallons or more of oil and site located near fish and wildlife sensitive environments or public drinking water intakes.	Operation	3 - 4 months	LIKELY	Quantity of oil is unknown at this time.

Agency	Permit/ Approval	Regulated Activity	Required Project Phase	Expected Review Time	Applicable to Project	Comments/Issues
EPA	Risk Management Plan	Potential accidental releases of hazardous chemicals that are used or stored onsite in greater than threshold quantities (Title III of CAAA).	Operation	See comments	MAYBE	May be triggered by storage/handling of ammonia, if SCR is used. Other potential chemicals include: _____ (Review list of chemicals with Larry)
FAA	Notice of Proposed Construction or Alteration	Construction of an object which has the potential to affect navigable airspace (height in excess of 200' or within 20,000' of an airport).	Construction	3 - 4 months	YES	Courtesy notice recommended to FAA for structures that do not exceed 200'. FAA may require lighting or marking of stack or temporary construction crane.
FERC	Exempt Wholesale Generator (EWG) Status	Selling electric energy at wholesale to a utility or other generator.	Construction	3 - 4 months	YES	Self-certification available. Sometimes sought to establish status as non-regulated utility.
USFWS	Section 7 Endangered Species Act Review	Confirmation of no impacts to federal threatened and endangered species.	Construction	1 - 2 months, initial consultation. Up to a year or longer may be required to complete species surveys.	YES	Consultation may be required if species and/or habitat on site or along off-site utility interconnection right-of-way may be impacted. See also State Department of Game and Fish.
FEDERAL	NEPA	Major federal action affecting the environment, typically triggered by work on federal lands, issuance of a federal permit, such as a COE permit, or federal funding.	Construction	Cat. Exclusion, 1 - 2 mths, EA, 9 - 12 months, EIS, 18 - 24 months	MAYBE	If triggered, project may qualify for categorical exclusion, or may be required to develop and EA. If a FONSI cannot be granted, an EIS will have to be developed.

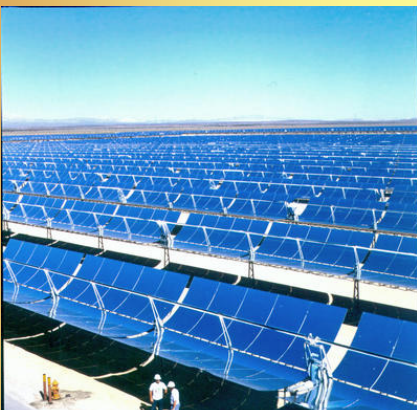
Agency	Permit/ Approval	Regulated Activity	Required Project Phase	Expected Review Time	Applicable to Project	Comments/Issues
STATE						
NMPRC	Certificate of Public Convenience and Necessity	Construction of power plant by public utility.	Construction	6 - 12 months	?	Will require application submittal including conservation plan.
NMPRC	Location Approval	Construction of a merchant plant \geq 300 MW	Construction	6 - 16 months	?	No approval is required for merchant plants < 300 MW. PRAC must make a decision within 6 months, unless they determine there are environmental concerns associated with related t-lines; an additional 10 months for review is then allowed by statute.
NMED	New Source Review Construction Permit	Construction of a stationary source with a potential emission rate > 10 ppm or 25 tpy of any regulated air contaminate for which there is a NAAQS or NM AAS.	Construction	9 - 12 months	MAYBE	Hidalgo, Grant, and Luna counties are in attainment for all priority pollutants. Project may qualify for General Construction Permit 4.
NMED	General Construction Permit 4 (CGP 4) for Combustion Sources and Related Equipment	Construction of a minor source in an attainment area.	Construction	30 days	MAYBE	Operating a 12.5 MW boiler may qualify it as a minor source, depending on the annual hours operated. Minor sources may qualify for CGP 4. Applicant may register under predetermined operating scenarios, as long as they are able to meet the distance requirements and emission limits for that scenario, as well as comply with a number of other permit conditions.

Agency	Permit/ Approval	Regulated Activity	Required Project Phase	Expected Review Time	Applicable to Project	Comments/Issues
NMED	Acid Rain Operating Permit	Title IV of CAAA, applicable to fossil fuel fired units > 25 MW.	Operation	6 - 24 months	NO	Title IV applications must be submitted on the date on which the unit commences operation. Allowances and CEM certification will be required. Proposed generator will not exceed 12.5 MW.
NMED	Title V Operating Permit	Title V of CAAA or Federally Enforceable State Operating Permit for significant air emission sources.	Operation	18 months after agency receipt of administratively complete application.	LIKELY	Both PSD and Title V approvals are required before construction.
NMED	Ground Water Discharge Permit	Any discharge of effluent or leachate that moves directly or indirectly into ground water.	Construction	180 days, if no hearing is held.	LIKELY	No General Permits are available at this time. Public notice will be required if NMED determines that there is significant public interest in the project.
NMED	Section 401 Water Quality Certification	State approval for federal action impacting state waters.	Construction	2-3 months	MAYBE	Required for COE Section 404 and NPDES permits. This is the primary tool the NMED uses to control water quality.
NMED	Hazardous Waste	Generation , storage , and disposal of hazardous waste.	Construction and Operation		MAYBE	Assume facility will not be a LAG (> 2200 # hw) Hazardous Waste Management Facility, and that it will qualify for either a CESQG (< 220 # hw) or an SQG (>220 - < 2200 # hw). (Larry check on this).
USE	Water Rights Permit	Water Appropriation	Operation		YES	
MDOT	Crossing Permit	Transmission lines and pipelines crossing federal and state highways.	Construction	2 - 3 months	LIKELY	

Agency	Permit/ Approval	Regulated Activity	Required Project Phase	Expected Review Time	Applicable to Project	Comments/Issues
MDOT	Oversize loads Permit	Oversized loads on interstate highways and into plant site.	Construction		LIKELY	
NMDG&F	Endangered Species Act Compliance	Confirmation of no impacts to state threatened and endangered species.	Construction	1 - 2 months for initial NMDG&F review, surveys to determine impact to listed species may take up to a year or longer.	YES	Consultation may be required if species and/or habitat on site or along off-site utility interconnection right-of-way may be impacted. A number of invertebrates and vertebrate species are listed as occurring in Luna, Grant, and Hidalgo Counties in the NMDG&F's 2004 Biennial Review of T&E Species of New Mexico, Final Draft Recommendation
NMDCA / SHPO	Archeological and Historical	Activities that could potentially affect archeological or historical resources.	Construction	3-4 months	YES	
TYPICAL LOCAL PERMITS						
Planning Department	Site Plan Approval	Site development.	Construction	6 - 12 months		
Zoning Department	CUP/SUP Permit, Variances	Establishment of power generation and cogeneration plants as a permitted use.	Construction	9 - 12 months		
Building Department	Building Permits	Construction of facility.	Construction	1 month		Review of construction drawings and inspections.
	Certificate of Occupancy	Facility Operation.	Operation	1 month		
Water Department	Potable water system extension and connection	Extension of existing water supply pipelines to site.	Construction	3 months		Appropriate of city water, if available.

Agency	Permit/ Approval	Regulated Activity	Required Project Phase	Expected Review Time	Applicable to Project	Comments/Issues
Sewer Department/ Health Department	Pretreatment Permit/Sewer system connection	Discharge of wastewater to sewer line/local wastewater treatment plant.	Construction/ Operation	3 months		Discharge of wastewater to municipal wastewater treatment works, if applicable.
Fire Marshal	Fire Safety Approval	Installation of fire protection system.	Construction	2 months		
Fire Marshal	Petroleum Storage Tank Approval					
ABBREVIATIONS BLM--Bureau of Land Management CAAA--Clean Air Act Amendments of 1990 COE--US Army Corps of Engineers CUP/SUP--Conditional Use or Special Use Permit EA--Environmental Assessment EPA--US Environmental Protection Agency EWG--Exempt Wholesale Generator FAA--Federal Aviation Administration FERC--Federal Energy Regulatory Commission FONSI--Finding of No Significant Impact NAA--Non-Attainment Area NEPA--National Environmental Policy Act NMPRC--New Mexico Public Regulation Commission NMDG&F--New Mexico Department of Game and Fish NMDCA--New Mexico Department of Cultural Affairs NMED--New Mexico Environmental Department NSR--New Source Review PSD--Prevention of Significant Deterioration SHPO--State Historic Preservation Officer SPCC--Spill Prevention Control and Countermeasure SWPPP--Storm Water Pollution Prevention Plan USFWS--US Fish and Wildlife Service						

Appendix B
New Mexico Concentrating Solar Power Feasibility Study



NEW MEXICO CONCENTRATING SOLAR POWER FEASIBILITY STUDY

ISSUES AND OPPORTUNITIES
ASSOCIATED WITH USE OF
RENEWABLE ENERGY
CERTIFICATES AS AN ENERGY
MARKETPLACE CURRENCY

NOVEMBER 2004

PREPARED BY:

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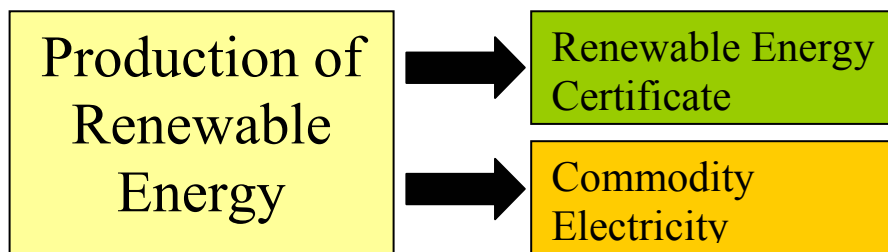
Jan Hamrin

RENEWABLE ENERGY CERTIFICATES

1.1 What is a Renewable Energy Certificate?

Renewable Energy Certificates (RECs) are created when a renewable energy facility generates electricity. Green electricity can be thought of as containing two components, the commodity electricity and the benefits or attributes. A REC represents the separable bundle of non-energy attributes (environmental, economic and social) associated with the generation of renewable power.¹ Each unique certificate represents all of the benefits of a specific quantity of renewable generation, namely the benefits that everyone receives when conventional fuels, such as coal, nuclear, oil, or gas, are displaced. For each kWh of electricity generated from a renewable source, a corresponding REC is assumed to be generated, regardless of whether this REC is traded separately from the energy (See Figure 1 below). RECs are sometimes also referred to as green tags, green tickets, renewable certificates, Tradable Renewable Certificates (TRCs), and T-RECs (tradable renewable energy certificates).²

Figure 1: Renewable Energy Certificates³



1.2 Renewable Energy Certificate Uses

RECs are used in many different contexts for different purposes. This fact sometimes creates confusion for those unfamiliar with the full range of their use. Currently, there are four primary uses for RECs in electricity markets.⁴ For all these uses, the REC creates a unique and verifiable claim to renewable generation attributes. (1) RECs are generally sold separately from their associated energy in wholesale markets. (2) In retail markets they may be sold separately as an independent “product” or may be combined with electrical energy at the point of sale to create a renewable electricity offering (See Figure 2 below). (3) In several US States, Europe and Australia, RECs are used as an accounting tool to measure and track renewable electricity generation. In such an application, a REC is created for every unit of renewable electricity output (usually

¹ Hamrin, Jan and Meredith Wingate. “Regulator’s Handbook on Tradable Renewable Certificates.” Center for Resource Solutions, May 2003.

² Hamrin, et al.

³ Green-e Web site (www.green-e.org)

⁴ Hamrin et al.

denominated in MWh) and no more than one REC can be created for any given MWh. (4) RECs are used in both retail and wholesale electricity markets, by environmental and utility regulators to demonstrate compliance with state mandates and other energy programs, and in pollution trading markets. New uses are being developed for RECs as electricity markets evolve and as savvy businesses create new ways to sell and finance renewable projects. These four uses are described in greater detail below.

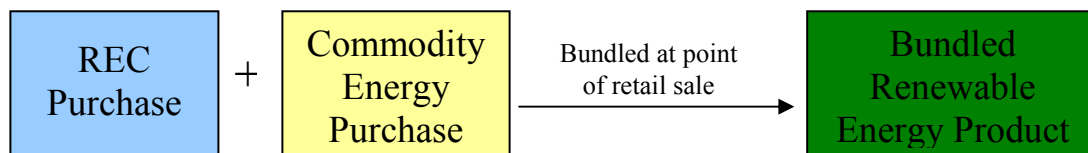
Wholesale Market Trading Tool:

RECs are used in wholesale markets to facilitate renewable electricity trading. Instead of selling bundled renewable energy through bi-lateral contracts that require scheduling and transmission, RECs are sold separately from the electricity on the wholesale level. The renewable generator can schedule their electricity generation with the local system operator according to contracts that exclude the attributes, or sell into the spot market. In this case, the renewable generator has created contracts for the energy without the RECs. From a renewable generator's point of view, the creation of a REC helps to clearly establish their property rights and ownership of the RECs, which they can cede or sell to another party.

Renewable Purchasing and Trading Tool for Retail Marketers:

RECs are used by renewable electricity marketers to meet the renewable obligation in their retail green electricity products. Renewable providers purchase RECs and combine them at the point of sale with generic system electricity to create a renewable electricity product that is sold at the retail level (See Figure 2). For many marketers who are unwilling or unable to enter into long-term energy contracts with renewable generators, this is a simpler and easier way to procure renewable electricity and it reduces the problems associated with scheduling and delivering power with intermittent resources and a small customer base.

Figure 2. REC Use in Renewable Electricity Products



Retail REC-only Product:

RECs are also sold separately from electricity as a stand-alone product. Currently there are nearly thirty retail REC products on the market.⁵ These types of products are frequently marketed on the Internet by independent companies not serving electricity load. Retail REC-only products offer customers that do not have access to green power through a utility green pricing program or competitive marketer the opportunity to support green power. REC-only products may also be sold in conjunction with the utility

⁵ Green Power Network Web site (<http://www.eere.energy.gov/greenpower/>)

in lieu of a green pricing program in both monopoly and competitive markets. The creation of a REC establishes property rights and creates a currency that can be bought or sold individually from electricity by end-use customers.

Used for Pollution Allowance or Compliance Purposes:

In order for a REC to be used in a pollution market, it must be converted from an energy tool measured in MWh to a pollution tool, denominated in pounds of pollution or avoided pollution. Although there are few examples in the US where a REC has been converted into a pollution allowance or pollution credit for environmental compliance purposes, RECs are regularly used by large companies and other organizations that want to voluntarily reduce their emissions profile, or boast of a climate neutral footprint. In addition, there are indications that RECs may be used in the future in state or federal emissions trading programs.

One important point to note, however, is that a REC may be used in energy markets OR converted to pollutions allowances but not both simultaneously unless explicitly allowed in the law or rules governing the programs. Under current market practices, only “whole” RECs are being sold; therefore, to use a single REC for both purposes would be double counting. In the future, it is conceivable that a REC could be disaggregated, or subdivided such that a portion of the REC could be used as a pollution allowance, and the remainder could be sold in energy markets. However, at present time, disaggregation of RECs is not recommended.

Accounting and Verification Tool:

RECs are also used as a generation attribute accounting mechanism for states implementing an RPS or calculating the system mix for consumer disclosure requirements. RECs may also be used as an accounting tool to support retail claims for differentiated “green” products, i.e. to verify that a supplier purchased the renewable energy claimed to consumers. In these instances, the REC is created as a tracking and accounting tool to show the environmental and other characteristics of the electricity that has been generated and sold. By issuing a unique certificate for every MWh or every renewable MWh and then tracking that certificate from source to sink, state regulators can easily determine whether a utility has met its renewable mandate and what types of generation should be reported on environmental disclosure labels. RECs can perform this function whether or not they are transacted separately or bundled with electricity. As described above, RECs exist outside of regulatory programs, though often times accounting systems that are used to monitor compliance with regulatory programs are the mechanism that validate the existence of a REC, establish property rights, and in some people’s view, make the REC “real” by giving it a serial number or some other unique identifier. NARUC passed a resolution supporting the development of attribute-based tracking systems.

Renewable certificate tracking systems are currently operating in: 1) New England: NEPOOL GIS; 2) Texas: ERCOT; and 3) Wisconsin. Tracking systems are in development in the Mid Atlantic: PJM GATS; Midwest: Iowa, Minnesota, Wisconsin,

North Dakota and South Dakota; and the Western Interconnect: WREGIS⁶ covering the western US, Alberta, British Columbia, and Baja Norte Mexico. WREGIS will be the largest tracking system when it becomes operational in 2005 and will include the entire state of New Mexico. WREGIS is sponsored by the California Energy Commission and the Western Governor's Association. WREGIS was conceived at the WGA Energy Summit in 2002 attended by Governor Bill Richardson

In June 2002, the Western Governors' Association adopted an amendment to its resolution, *Western States' Energy Policy Roadmap*, supporting the creation of an independent regional tracking system to provide data necessary to substantiate and support verification and tracking of renewable energy generation. The resolution included a management directive charging WGA to bring Western stakeholders together to help define the institutional structure, to design operating guidelines and to identify information needed to support tracking and registration of renewable energy generation and accounting of certificates in the Western Interconnection.

The California Legislature has charged the California Energy Commission with developing a tracking system for implementing California's Renewable Portfolio Standard (RPS). On October 8, 2003, the California Energy Commission adopted the *Renewable Portfolio Standard: Decision on Phase 2 Implementation Issues*, which recommends that the Energy Commission staff work with the WGA to develop a regional certificates-based renewable energy tracking system.

The Western Governors' Association and the California Energy Commission are working collaboratively to develop a Western-wide renewable tracking system. The WGA, with assistance from the Commission, recently surveyed regulators, utilities, market participants, tribes, developers, and other stakeholders, to solicit input on the development of a Western tracking system

1.3 Current State of Retail REC Markets

There are currently 24 REC marketers selling 29 REC products.⁷ In 2003, approximately 5,000 retail customers purchased RECs, representing 700 TWH. Most of these sales were concentrated in the Mid-Atlantic and Northeast, where REC marketers tend to be most active.⁸ The vast majority of this volume was sold to commercial customers.

The Center for Resource Solutions collects trend information on competitive retail markets green power sales through its Green-e⁹ verification procedures. Recognizing that

⁶ Western Renewable Energy Generation Information System. For more information on WREGIS go to www.westgov.org/wieb/wregis/

⁷ Green Power Network Web site (<http://www.eere.energy.gov/greenpower/>)

⁸ Bird, Lori and Blair Swezey. "Green Power Marketing in the United States: A Status Report." 7th Ed., National Renewable Energy Lab, September 2004.

⁹ Green-e is a voluntary certification program for renewable electricity products. The Green-e Program sets consumer protection and environmental standards for electricity products, and verifies that Green-e certified products meet these standards. The Green-e Renewable Electricity Certification Program is

Green-e products represent only a subset of the market, the following provides more detailed information on REC markets and REC sales. In 2003, Green-e certified 1800 TWH of REC transactions, 81% of which were sold in the wholesale markets, 18% were sold in commercial markets, and less than 1% in residential markets. The majority of all (retail and wholesale) Green-e certified REC sales took place in the Northwest, Mid-Atlantic and West. The West, Mid-Atlantic and Northeast accounted for the majority of residential customers and sales. The West accounted for over 35% of residential customer sales, while the Mid-Atlantic accounted for 27% of residential sales and the Northeast accounted for 24% of residential sales. The West and the Mid-Atlantic dominated non-residential REC demand. The Mid-Atlantic accounted for 54% of non-residential sales, while the West accounted for 12% of non-residential sales. Certified REC wholesale transactions were concentrated in the Northwest (47%), South (34%) and West (11%).¹⁰

Retail prices for RECs range from approximately \$0.01/kWh to \$0.025/kWh for residential customers, while some products are as much as \$0.04 or \$0.05/kWh. There is one 100% solar product that is being advertised as \$0.20/kWh. Large commercial customers can generally negotiate lower prices.¹¹

To fully appreciate the voluntary market for RECs it is necessary to also consider the green power market, where RECs are traded at wholesale and rebundled with electricity at the point of sale to create “green” electricity. In 2003, 500 utilities sold 1300 TWH of renewable electricity to 265,000 customers¹². Of these 500 utility green pricing programs, NREL estimates that 17 were responsible for 90% of the sales, suggesting that many utility green pricing programs are either poorly managed or not designed to create consumer demand for green power, but rather to forestall government regulation. In deregulated markets 33¹³ competitive electric service providers sold 1900 TWH of renewables to 150,000 customers.¹⁴ Much of the volume of these “bundled” products came from RECs.

Competitively marketed green power products generally carry a price premium of between 1¢/kWh and 2¢/kWh, although offerings range from about 0.1¢/kWh to 5¢/kWh. The price premium charged depends on several factors such as the price of “standard offer” or default service, whether incentives are available to green power marketers or suppliers, and the cost of renewable energy generation available in the regional market. Some marketers charge prices very close to the default market price but also charge a monthly service fee; others offer fixed price products, which provide customers with protection against increasing prices for a specified period of time, usually only one year.¹⁵

administered by the non-profit Center for Resource Solutions. In 2003, Green-e certified RECs represented 52% of all retail REC sales.

¹⁰ Green-e 2003 Verification Report.

¹¹ Bird, et al.

¹² Bird et al.

¹³ Green Power Network Web site (<http://www.eere.energy.gov/greenpower/>)

¹⁴ Bird et al.

¹⁵ Bird, et al.

The price premiums charged in green pricing programs range from 0.6¢/kWh to as much as 17.6¢/kWh, with a median of 2.0¢/kWh and a mean of 2.62¢/kWh. Programs that feature solar-only products represent the high end of the range. A handful of utilities offer volume discounts or lower premiums to nonresidential green power customers.¹⁶

1.4 Current State of Retail Solar REC Market in Voluntary Green Power Markets

Wind energy is the most commonly used source in REC and green power products representing over 95% of the product content.¹⁷ Solar is no more than 1% of the product content of all green power products. Mainstay Energy and NUON Renewable Venture are selling 100% solar RECs. Mainstay is selling their 100% solar RECs for \$0.20/kWh. However, many REC and green power products include a blend of resources, such as biomass and solar. Bonneville Environmental Foundation sells a REC product that includes less than one percent solar RECs. The rest of the blend is comprised of 98% new wind RECs and approximately 1% biomass. The published price for this REC is \$0.02/kWh. Sterling Planet is selling a REC product comprised of 5% solar RECs. The rest of the blend is comprised of 45% new wind and 50% new biomass RECs. This REC product is being sold for \$0.016/kWh. Sun Power Electric Corporation is selling a 1% solar REC product. The rest of the blend for this product is landfill gas. The price listed for this REC product is \$0.036/kWh.¹⁸ According to the Evolution Markets September 2004 Market update, new solar RECs are trading in the voluntary market in the WECC region at \$50.00/MWh and there were approximately 100 MWh of RECs available.¹⁹ In 2003, approximately .03% of Green-e certified REC sales were from solar RECs. Of the entire 3.1 million MWh of Green-e certified renewables sold in 2003, solar represented 1,421 MWh or approximately 0.05%.

Table 1: Solar REC Market Share of Total REC Sales

<i>Year</i>	<i>Total REC Sales (MWh)</i>	<i>Average REC Price</i>	<i>Total Solar REC Sales (MWh)</i>	<i>Solar REC Price Range²⁰</i>
<i>2003</i>	7,000,000	1¢/kWh to 2.5¢/kWh	1400 ²¹	5¢/kWh to 20¢/kWh
<i>2002</i>	300,000 ²²	1¢/kWh to 2.5¢/kWh	500 ²³	5 ¢/kWh to 20¢/kWh

¹⁶ Bird, et al.

¹⁷ Bird, et al.

¹⁸ Green Power Network Web site

¹⁹ Evolution Markets, Monthly Market Update, September 2004, www.evomarkets.com.

²⁰ Current solar markets are small and not very liquid. Therefore, identifying a market clearing price for solar RECs is not plausible.

²¹ Information on the product content of RECs is very limited. This number is extrapolated based on Green-e verification results.

²² Information on the volume of RECs is very limited. This number is extrapolated based on Green-e verification results.

²³ Information on the product content of RECs is very limited. This number is extrapolated based on Green-e verification results.

As discussed above, RECs are often also traded at wholesale and rebundled with electricity at the point of sale to create competitive green electricity products and green pricing products. According to the Green Power Network Web site 43 of the 149 green pricing products listed include solar in their green pricing mix. Nine of these programs are contribution programs. The City of Tallahassee in conjunction with Sterling Planet offers a 100% solar product which sells for an 11.6 cents per kilowatt-hour premium.²⁴

The products offered in competitive markets tend to differ from those offered by utilities in that they may contain a mix of electricity generated from new and preexisting renewable energy projects; whereas, utilities generally use only new renewable energy supplies. Competitive suppliers are more concerned about price competition, and existing resources are typically available at lower costs.²⁵ The Green Power Network Web site lists 78 retail green power product offerings as of July 2004. Of these 78 products, only 10 are listed as including solar in the resource mix. For all but one of these products the solar portion is 1% of product content or lower. Sterling Planet in conjunction with Narragansett Electric offers a 25% solar product for a 1.98 cents per kilowatt-hour premium. The rest of this product includes 40% small hydro, 25% biomass and 10% wind. The other nine products charge between 0.95 and 2.5 cents per kilowatt-hour. Almost all of these products include a large amount of small hydro. The rest of the product is often made up of landfill gas, biomass or wind.²⁶

1.5 How do RECs Fit into Voluntary and Compliance Markets?

RECs are the fastest growing portion of the voluntary green power market. RECs are sold in stand alone products as described above, but RECs are also bought to substantiate bundled green power products in regulated and deregulated markets. RECs are the dominant compliance tool for renewable energy compliance markets. Every state that has some kind of renewable energy mandate (RPS, Mandate, or Goal) either has an operable renewable energy certificate tracking system or a system is in the design stage.

However, while RECs, in general, can universally serve Voluntary renewable energy markets, the rules and manner in which they can server Compliance markets are less certain, more restrictive, and still evolving.

In the CRS Task 2 report for this study, the so-called compliance market for solar energy throughout the southwestern states is reviewed in detail. Market analysis for those states with the most aggressive renewable energy portfolio standards (markets are reviewed for California, Texas, Colorado, Nevada, Arizona and New Mexico) shows that the California market is potentially larger than that of all of the other southwest states combined.

²⁴ Green Power Network Web site (<http://www.eere.energy.gov/greenpower/>)

²⁵ Bird et al.

²⁶ Green Power Network Web site (<http://www.eere.energy.gov/greenpower/>)

1.6 Evolving California Market Opportunities

At present, renewable electric power generated anywhere within the WECC is eligible to serve the RPS obligations of California load serving entities (LSE). However, present regulation requires that the renewable electricity be delivered to California load centers on a “contract path” basis. This requirement ensures that adequate renewable energy resources are developed to serve the entirety of California’s RPS goals, but results in a degree of inflexibility that may create transmission and other barriers to exploiting the most cost effective or most desirable renewable resources. A more liberal approach to credit trading could allow for a more optimal deployment of renewable energy resources to serve California RPS needs.

California's renewable energy policy related to credit trading is in the process of being reexamined. It is widely assumed that some form of flexibility in credit trading is needed in order for the state to meet both its accelerated and long-term renewable energy goals. On November 10, a meeting was held in California to explore the potential use of “unbundled” RECs as a qualified renewable energy resource under within the RPS. The meeting included representatives of the CPUC, the CEC, several utilities, and other stakeholders (including CRS).

The pros and cons of allowing unbundled RECs were discussed at some length. The CEC has previously conveyed a case for allowing unbundled RECs, which is summarized in Appendix A of this report. Staff from the CPUC articulated several reasons for maintaining the status quo – principally to ensure that the air emissions benefits of added renewable energy accrue by ensuring that the renewable energy is delivered to the LSE, thereby offsetting less clean power generation that otherwise serves the region.

A committee has been formed to further review this issue. Should a decision ultimately be made to allow unbundled RECs to serve California RPS obligations, the ability of New Mexico CSP to serve that market will be greatly enhanced.

1.7 Prospects for significant, future New Mexico Solar REC sales into national REC Markets

Available market data suggest solar RECs are a very small if not symbolic part of the voluntary green power market. Customer surveys consistently rate wind and solar as the most popular renewable technologies among consumers. However, due to price, volume, economies of scale and several other factors, the voluntary solar REC market is limited despite the good will of consumers.

Opportunities for New Mexico Solar RECs in Voluntary Markets:

Because solar REC prices are substantially higher than other REC prices, green power marketers resort to blending 1-5% solar into green power products dominated by wind and biomass resources. This allows marketers to capture consumer’s good will towards solar energy while offering a product at an affordable price point. As prices for solar RECs fall to levels more competitive with other resources, solar RECs will increase their

share of product content. Solar content in green power products offered to customers of Massachusetts Electric and Narragansett Electric in New England are typically 1-2.5%, but one product offers 25% solar.

Solar RECs included in blended REC products will find national markets, because REC buyers prefer to support:

- renewables at the lowest price regardless of location;
- specific preferred technologies such as solar and wind;
- newly built renewable facilities over older more local facilities; and
- Renewables that offset conventional generation in power pools with higher than average emission displacement values.

New Mexico power generation has one of the highest emission profiles in the US and should therefore seek to capitalize on the high emission displacement value of a New Mexico solar REC. One REC marketer offers RECs generated on Native American land as an additional selling point. The social and human opportunity value of RECs is an attribute that is not commonly marketed.

Direct marketing of New Mexico CSP RECs to national and multinational corporations:

A growing number of multinational companies are greening their operations through large REC purchases. The EPA's Green Power Partnership, the first government-administered recognition program for green power purchases, now boasts over 500 members with a purchasing capacity of over 2 million MWH of green power annually. Notable Green Power Partners include Johnson and Johnson, Staples, Whole Foods Markets, University of Pennsylvania, FedEx Kinko's and Silk Soymilk. Many of these organizations are using RECs to meet their Green Power Partnership commitments.

A similar group, the Green Power Market Development Group (GPMDG) aims to develop corporate markets for 1000 MW of new, cost competitive green power by 2010. It is a collaboration of 12 leading corporations and the World Resources Institute dedicated to building corporate markets for green power. In the late 1990s General Motors, British Petroleum, Monsanto and the World Resources Institute undertook the Safe Climate, Sound Business Initiative (SCSB) to overcome the apparent conflict between energy needs and the desire to reduce greenhouse gas emissions (80% of which is energy derived from fossil fuels, the principle source of anthropogenic greenhouse gas emissions).²⁷ In September 2003, nine GPMDG member companies and WRI completed the largest purchase of RECs in the United States.²⁸ As of September 2003, the GPMDG had purchased 36 MW of RECs, which is almost a third of their total purchases as of this time.²⁹

²⁷ Green Power Market Development Group Web site (<http://www.thegreenpowergroup.org/>)

²⁸ King, Marcus D., Paloma Sarria, Daniel J. Moss, and Neil J. Numark. "U.S. Business Actions to Address Climate Change: Case Studies of Five Industry Sectors." Green Business Network, Washington, DC; November 2004.

²⁹ Green Power Market Development Group Web site (<http://www.thegreenpowergroup.org/>)

Also in 2003, Johnson and Johnson completed a large purchase of RECs. Twelve business units within the company combined to purchase more than 162,000 MWH of biomass RECs over three years. This large REC purchase provided Johnson and Johnson with an efficient and cost effective means of addressing the company's climate change goals. If Johnson and Johnson had opted for a traditional green power purchase involving delivered electricity, the twelve different business units might have had to contract with twelve different green power providers and significant obstacles might have arisen. Most notably, business units acting independently in different states and regions would not have been able to benefit from the economy of scale provided by a large aggregate purchase.³⁰

Other notable REC purchasers include Nike, Cargill Dow, Choice Organic Teas, New Leaf Paper, Interface Fabrics Group, Kaiser Permanente and Odwalla. While this market is young, it is expected to grow significantly in the coming years. Consumer preference reports indicate that customers are interested in purchasing products from environmentally aware companies and we expect that large national companies will utilize the ease and liquidity that TRCs offer to satisfy this demand.

It may be possible to New Mexico CSP to target this growing market. Since these markets are national or global in scope, the relative geographic isolation of New Mexico may not be a problem (much of the solar REC sales into small individual or utility green pricing programs require that the solar generation be local).

Summary:

REC sales could represent an important outlet for a portion of future New Mexico Concentrating Solar Power. To maximize the impact and benefits of a RECs approach, a portfolio of REC marketing and sales approaches should be taken:

- Include New Mexico CSP in all New Mexico green pricing programs to increase their local appeal;
- Market New Mexico CSP RECs directly to large multinational commercial and industrial enterprises;
- Highlight the high emission displacement value of New Mexico solar RECs sold onto the national market;
- Package New Mexico solar RECs with other lower cost renewables
- The Texas direct access electricity market has created the most active bundled green power market in the US and out of Texas RECs are being imported into Texas to serve this market,
- The operation of WREGIS will open up New Mexico solar RECs to a 13 state and 3 country trading area adding greater liquidity to the solar REC market.

³⁰ Aulisi, Andrew, Jennifer Layke and Samantha Del Pino. "A Climate of Innovation: Northeast Business Action to Reduce Greenhouse Gases." World Resources Institute, Washington, DC; 2004.

APPENDIX A: RECENT SUMMARY PERSPECTIVE FROM THE CALIFORNIA ENERGY COMMISSION ON THE USE OF UNBUNDLED RECs UNDER THE CALIFORNIA RPS

California Energy Commission - REC reference in the 2004 IEPR

Unbundled Renewable Energy Certificates

Trading unbundled Renewable Energy Credits (RECs) may be an effective way to assist utilities that have fewer local renewable resources to meet the state's renewable energy goals in the future. Currently, unbundled RECs are not allowed in California's RPS program, and RECs procured for RPS compliance must remain bundled with the associated renewable electricity.

A REC typically represents the environmental attributes of renewable energy as a separate commodity from the electricity. For this discussion, the term is used in its broadest definition to mean the "renewable attributes" of a given unit of renewable-based generation, as distinct from the underlying electrical energy. A REC may be "bundled" and sold together with the underlying electricity, or a REC may be unbundled and the renewable attribute sold separately.

Senate Bill 1478 (Sher) would have required the Energy Commission, in consultation with the CPUC, to establish the definition of a REC to ensure compatibility with standard contract terms and conditions and protect the interests of ratepayers. However, the Governor vetoed the bill because he believed that it would create a renewable credit market with several onerous restrictions. Unbundled RECs represent a potential advantage for California because they could reduce the need to add transmission lines, relieve transmission congestion, and help meet renewable energy goals. Yet this potential advantage will depend on the location of the renewable resource and whether transmission lines are available to transfer the electricity. Although RECs can help utilities transfer "renewable attributes" between utilities, RECs cannot eliminate the need for transmission infrastructure to access renewable energy or meet RPS targets.

Even with these potential transmission constraints, unbundled RECs may be a reasonable means for electric service providers and community choice aggregators to use to comply with the RPS. Unlike the IOUs and municipal utilities, electric service providers and community choice aggregators are typically small entities, who may lack a guaranteed revenue stream or credit backing for long-term power purchase agreements. Electric service providers and community choice aggregators may of necessity have to enter into short-term electricity contracts, with relatively small financial commitments and the flexibility to respond to market changes. For these two groups, unbundled RECs may be an appropriate compliance option.

The CPUC and other parties, however, have raised a possible disadvantage to this approach: whether allowing unbundled RECs would create environmental justice issues. For example, if an IOU procured unbundled RECs from a new wind facility outside its

service territory, along with matching fossil fuel-based electricity generated locally, to serve its load, then the renewable energy would not result in local air quality benefits.

The CPUC also indicated that allowing unbundled RECs for the RPS could invite market manipulation, or double counting. If RECs were to become a feature of the RPS, the Energy Commission notes, then safeguards will be needed to ensure that a RPS contract for bundled renewable electricity is not stripped of its electricity. The Western Renewable Energy Generation Information System accounting system, currently under development, can help to prevent double counting.

Through the ongoing RPS proceedings, the CPUC and Energy Commission collaborative staff will further investigate the advantages and disadvantages of incorporating unbundled RECs into the RPS for IOUs as well as for electric service providers and community choice aggregators.

Appendix C
Markets for Bulk Solar Power in the Southwest



MARKETS FOR BULK SOLAR POWER IN THE SOUTHWEST

ISSUES AND OPPORTUNITIES
ASSOCIATED WITH SERVING
MARKETS OUTSIDE OF NEW
MEXICO WITH NEW MEXICO
SOLAR POWER



NOVEMBER 2004



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MARKET OVERVIEW:

Renewable energy markets are growing rapidly in the six southwestern states of California, Texas, Arizona, New Mexico, Nevada, and Colorado. While early development of renewable energy (1980s and 1990s) in these states was largely attributable to Federal PURPA regulations, the anticipated large-scale future growth will largely be driven by statutory requirements. Each of these states has, or are contemplating, mandates that require load serving entities to use renewable energy as a portion of their delivered energy mix. These mandates, which vary in form and function from state to state, are based on either legislation or regulation. These so-called Renewable Portfolio Standard (RPS) programs are still in a highly evolutionary state.

A summary of these RPS “compliance markets” is provided for each southwest state below.

Arizona Compliance Market

Arizona’s Environmental Portfolio Standard (EPS) became effective on March 30, 2001. The Arizona Corporation Commission (ACC) started the EPS process with Decision #62506 in 2000, but it was Decision #63364 in February 2001 that approved the EPS. In March 2001, Decision #63486 resulted in small modifications to the rules in response to a request for reconsideration.¹

The Arizona RPS requires regulated utilities to provide a certain percentage of their electricity from new renewable sources. This starts at 0.2% in 2001, rising 0.2%/yr to 1% in 2005, and to 1.05% in 2006, then to 1.1% for 2007- 2012. At least 50% of the RPS must be new solar electricity through 2003, and at least 60% starting 2004.²

Under the Arizona RPS, new is defined as being generation installed on or after January 1, 1997. The RPS includes the following resources as solar renewables: PV and solar thermal electric. Non-solar renewables include: solar hot water and air conditioning, and in-state landfill gas, wind, and biomass (customer-sited applications are eligible). Solar hot water and solar air conditioning can contribute to the non-new solar portion of RPS if the provider contributed to the installation of the system. R&D investments can reduce the RPS target by up to 10% in 2001 and 5% in 2002-03.

The standard includes a caveat that if the cost of solar technologies does not decrease to a Commission-determined cost/benefit point by the end of 2004, the portfolio requirement will not continue to increase. On February 10, 2004, the Commission voted to allow the standard to continue increasing to 1.1% of electricity from renewables by 2007.

¹ Database of State Incentives for Renewable Energy (www.dsireusa.org)

² Wiser, et al.



Workshops will be held to determine whether a current surcharge on residential electric bills of up to 35 cents per month should be increased and whether a requirement that 60% of the renewable energy comes from solar resources should be modified or eliminated.³

Out-of-state solar is eligible if it is proven that the power reaches Arizona customers. Wind, landfill gas, and biomass must be in-state. Renewable energy credit multipliers provide additional incentives for in-state solar.

Arizona has a detailed system of credit multipliers for early installation before 2003, in-state installation or content, distributed solar, net metering, and utility green pricing. Starting in 2004, if new solar requirements are not met, then the ACC *may* be able to fine an LSE 30¢/kWh; whether this is allowed is to be determined after the 2003 cost/benefit evaluation. The proceeds would then likely go to a solar electric fund to finance solar facilities. But, today, no penalties exist for non-compliance.⁴

Funding for the EPS comes from existing system benefits charges and a new surcharge to be collected by the state's regulated utilities. The new surcharge is capped at 35¢ per month for residential customers, \$13/month for non-residential, and \$39/month for customers with loads over 3 MW. In total, at least \$15 - \$20 million is expected to be collected annually for the EPS.⁵

California Compliance Market

Legislation enacting California's Renewable Portfolio Standard (RPS) - SB 1078 - was signed by the Governor of California on September 12, 2002.⁶ The California RPS required Investor Owned Utilities (IOUs) to increase their renewable supplies by at least 1% per year starting January 1, 2003, until renewables make up 20% of their supply portfolios. The 20% requirement must be reached no later than 2017, but utilities may not have to meet the requirement if SBC funds are exhausted before the requirement is met: costs of renewables over a to-be-determined market price referent must be paid for by the state's SBC fund. Competitive Energy Service Providers (ESPs) are required to start increasing renewables by 2006 or when their direct-access contracts expire, whichever comes first.⁷ Municipal utilities are ordered by the legislation to implement RPS programs under their own direction.⁸

The RPS defines eligible resources as including the following; biomass, solar thermal electric, photovoltaics, wind, geothermal, fuel cells using renewable fuels, existing hydro under 30 MW, digester gas, landfill gas, ocean wave, ocean thermal, or tidal currents. New hydro is only eligible if it does not require new or incremental appropriations or diversions of water. Geothermal existing before September 26, 1996 is eligible only for adjusting a retail electric provider's baseline quantity of renewable energy, not for

³ DSIRE

⁴ Wiser, et al.

⁵ DSIRE

⁶ DSIRE

⁷ Wiser et al.

⁸ DSIRE



meeting the incremental 1% requirements. Eligible biomass has fuel supply requirements.⁹ Municipal solid waste is generally only eligible if it is converted to a clean burning fuel using a non-combustion thermal process. There are restrictions for some of these technologies.¹⁰

The California RPS allows out-of-state generators to be eligible, assuming that those generators deliver electricity into California.¹¹

Colorado Compliance Market

On Tuesday, November 2, 2004, Colorado voters approved Amendment 37, which requires utilities serving over 40,000 customers to acquire a portion of their electricity from renewable resources (this currently applies to the state's seven largest utilities)¹². Amendment 37 requires that this portion increase from less than two percent today to 10 percent of electricity sales by 2015. Four percent of the renewable energy (or 0.4 percent of covered electricity sales) would be required to come from solar energy. The Amendment would also establish a funding mechanism for solar, using a rebate to building owners who install solar systems, similar to funding mechanisms established in many of the state renewable energy funds.¹³

The Colorado renewable energy standard requires utilities with more than 40,000 customers to generate or acquire renewable energy equal to at least three percent of retail sales by 2007, increasing to six percent in 2011, 10 percent in 2015, and remaining at 10 percent each year thereafter.¹⁴

Municipal-owned utilities and rural electric cooperatives are given the option to remove themselves from Colorado PUC oversight by "self-certifying" a similar renewable energy standard. They also have the option under the proposal to exempt themselves from the standard by securing a majority vote from their customers.¹⁵

Amendment 37 defines eligible renewable energy resources as: solar, wind, geothermal, bioenergy (energy crops, forest and agricultural residues, animal wastes), landfill gas, small-scale (less than 10 MW) hydro, and fuel cells using renewable fuel sources. Because of its unique benefits and higher costs compared with other renewable energy technologies, solar energy receives additional support under the ballot measure. The standard requires that at least four percent of the total annual renewable energy supply (or 0.4 percent of the requirement) come from solar energy, half of which must be customer-sited.¹⁶

⁹ Wiser, et al.

¹⁰ DSIRE

¹¹ Wiser et al.

¹² DSIRE

¹³ Deyette, Jeff & Steve Clemmer. *The Colorado Renewable Energy Standard Ballot Initiative: Impacts on Jobs and the Economy*. Union of Concerned Scientists, Cambridge, MA; October 2004.

¹⁴ Deyette, et al.

¹⁵ Deyette, et al.

¹⁶ Deyette, et al.



The Amendment also requires the Colorado PUC to establish a REC trading system to track compliance and provide greater flexibility in meeting the annual requirements. A cost cap is included in the renewable energy standard, which protects all customer classes against the potential of higher than expected compliance costs. The maximum retail rate impact from meeting the renewable energy standard is set at 50 cents per month for the average residential customer of a qualifying utility.¹⁷ Under Colorado law it is illegal to charge different kinds of customers differently. For business customers, the rate cap is approximately 1%.¹⁸

Amendment 37 encourages renewable energy development in Colorado by providing extra credit (1.25 RECs) for each kilowatt-hour of renewable energy generated inside the state. To the extent that renewable energy facilities are constructed in Colorado, this will reduce the overall amount renewable energy required to meet the standard. However, by creating an incentive to develop renewable energy in Colorado, this provision will increase the local economic and air quality benefits.¹⁹

Utilities are required to enter into 20-year contracts for the acquisition of renewable energy under the Amendment. This will help further reduce renewable energy development costs by providing access to low-cost financing. Utilities are allowed to fully recover the costs incurred by meeting the renewable energy standard, including the potential for regulated utilities to earn a bonus on investments in renewable energy that yield a net economic benefit to consumers. The Colorado PUC is also authorized under the renewable energy standard to establish penalties for non-compliance.²⁰

Nevada Compliance Market

As part of its 1997 restructuring legislation, the Nevada legislature established a renewable energy portfolio standard. Under the standard, the state's two investor-owned utilities, Nevada Power and Sierra Pacific Power, must derive a minimum percentage of the total electricity they sell from renewable energy resources.²¹ In 2001 the state legislature revised the RPS to require 5% renewables in 2003 and increasing by 2% every two years, ending at 15% in 2013 and thereafter. The RPS requires that at least 5% of the RPS standard must be from solar (PV, solar thermal electric, or solar that offsets electricity, and perhaps even natural gas or propane).²²

The RPS defines eligible resources as solar (including solar that offsets electricity, and perhaps even natural gas or propane), wind, geothermal and biomass (includes agricultural waste, wood, MSW, animal waste and aquatic plants). Legislation in 2003 adds electricity produced from certain forms of waste heat or pressure under 15 MW in size as eligible. Certain small hydro plants (including pumped hydro used at mines) under

¹⁷ Deyette, et al.

¹⁸ See Renewable Energy Yes Web site; <http://www.renewableenergyyes.com/>

¹⁹ Deyette, et al.

²⁰ Deyette, et al.

²¹ DSIRE

²² Wiser et al.



30 MW in size are also now eligible, with limitations on water diversion, date of installation, and water use. On-site renewable generation qualifies.²³

According to the RPS, distributed renewable generation receives extra-credit multiplier (1.15), except that customer-sited PV receives a far larger credit multiplier (2.4). Waste tire plants are not eligible, except that customer-sited waste tire facilities that use “reverse polymerization” qualify for 0.7 credits per kWh. If an IOU helps fund an end-user’s solar thermal energy system that offsets electric use, then the IOU can count the consumption reduction against the RPS requirement.²⁴

Eligible renewables can be located in-state or out-of-state with a dedicated transmission line to an in-state utility. The transmission line cannot be shared with more than one other nonrenewable generator.²⁵

The Public Utilities Commission of Nevada (PUCN) adopted a temporary regulation on November 20, 2002 that allows energy providers to buy and sell renewable energy credits (REC). With the passage of four REC-related bills in the 2003 legislative session, the REC regulations are in the process of being revised. Retail energy providers complying with Nevada’s RPS can purchase credits from the owners of the REC. One REC will represent a kilowatt-hour of electricity generated from a renewable energy system, with the exception of photovoltaics, which counts as 2.4 kWh. RECs are valid for a period of five years.

New Mexico Compliance Market

The Public Regulation Commission (PRC) passed the RPS rule on December 17, 2002, and the rule became effective July 1, 2003. The RPS requires investor owned utilities to produce 5% of all energy they generate for New Mexico customers to be renewable by 2006.²⁶ RPS requirements increase by at least 1% a year, and utilities must reach 10% by January 1, 2011 and thereafter.²⁷

Under the RPS the following resources are defined as eligible, wind, hydro facilities under 5 MW, biomass, geothermal, landfill gas, fuel cells and solar. Utilities document compliance with the RPS through the use of renewable energy certificates, which represent kilowatt hours of renewable energy produced. The various sources of renewable energy have been assigned different values for the purposes of issuing certificates, calculating the percentage of electricity generated by renewables²⁸ and to encourage a diverse mix of renewable resources. The rates are listed below:

- 1 kWh wind or hydro = 1 kWh toward compliance;
- 1 kWh biomass, geothermal, LFG, or fuel cell = 2 kWh; and

²³ Wiser, et al.

²⁴ Wiser et al.

²⁵ Wiser et al.

²⁶ DSIRE

²⁷ Wiser et al.

²⁸ DSIRE



- 1 kWh solar = 3 kWh.

Other restrictions on resources include: co-firing or fuel switching facilities may only count the biomass contribution toward the requirement; and renewables developed in combination with a fossil fuel source may be eligible, but only the renewable portion counts toward the requirement. Undefined “preference” is given to in-state resources; otherwise, renewable electricity must be delivered in-state.²⁹

The rule also requires investor owned utilities and electric cooperatives (for coops - only to the extent that their suppliers under their all-requirements contracts make such renewable resources available) to offer a voluntary renewable energy tariff (green pricing program) for those customers who want the option to purchase additional renewable energy. These utilities must also develop an educational program to communicate the benefits and availability of its voluntary renewable energy program. In addition, the IOUs were required to file a renewable energy plan, which is a general long-term strategy for satisfying the RPS.³⁰

With the passage of SB 43 in 2004, the PRC is required to establish the "reasonable cost threshold," through hearings and research, by December 31, 2004. If the cost of renewable energy generation is above this PRC established level, the public utility will not be required to add renewable energy to its supply portfolio.³¹

SB 43 also reduces the RPS for nongovernmental customers at a single location or facility with consumption exceeding 10,000,000 kWh/yr. The number of kWhs of electricity from renewable sources procured for these customers is to be limited so that the additional cost of the RPS to each customer does not exceed the lower of 1% of that customer's annual electric charges or \$49,000. This procurement limit criterion is then increased by 1/5% or \$10,000 per year until January 1, 2011, when it remains fixed at the lower of 2 % of the customer's annual electric charges or \$99,000. The bill clarifies that this language in no way affects a public utility's right to recover all reasonable costs of complying with the RPS. It also provides the PRC the authority to defer recovery of the costs of complying with the PRS, including carrying charges.³²

Texas Compliance Market

On December 16, 1999, the Public Utility Commission of Texas issued the Renewable Energy Mandate Rule. This standard establishes the state's renewable portfolio standard, a renewable energy credits trading program (trading program), and defines the renewable energy purchase requirements for competitive retailers in Texas.³³

This legislation established capacity targets for renewable energy installation at 1280 MW by 2003, 1730 MW by 2005, 2280 MW by 2007, 2880 MW by 2009 (of this, 880

²⁹ Wiser et al.

³⁰ DSIRE

³¹ DSIRE

³² DSIRE

³³ DSIRE



MW can be from existing generation). Regulatory rules translate capacity targets into energy-based purchase obligations.³⁴

The RPS defines qualifying renewable energy sources as solar, wind, geothermal, hydro, wave or tidal, and biomass including landfill gas. Self-generation is eligible if it meets metering requirements.³⁵

The Public Utility Commission of Texas established a Renewable Energy Credits Trading Program that started July 1, 2001 and continues through 2019. A Renewable Energy Credit (REC) represents one megawatt hour (MWh) of qualified renewable energy that is generated and metered in Texas.³⁶ To be eligible to produce TRCs and meet the incremental RPS goals, a facility must either be considered new or be small. A new facility must have an initial operation date after Sept 1, 1999. A facility is small if it has a capacity of less than 2 MW. Existing renewable facilities can offset an LSE's renewable energy purchase obligations, but are not allowed to trade TRCs.³⁷

Each retailer in Texas will be allocated a share of the mandate based on that retailer's pro rata share of statewide retail energy sales. The program administrator will maintain a REC account for program participants to track the production, sale, transfer, purchase, and retirement of RECs. Credits can be banked for 3 years, and all renewable additions have a minimum of 10 years of credits to recover over-market costs. A penalty system has been established for providers that do not meet the RPS requirements. The penalty is the lesser of \$50 per MWh or 200% of the average cost of credits traded during the year. A Capacity Conversion Factor (CCF) is used to convert MW goals into MWh requirements for each retailer in the competitive market. The CCF is administratively set and equal to 35% for the first two compliance years, thereafter based on the actual performance of the resources in the credits trading program.³⁸

Out-of-state generation is not eligible for TRCs, unless there is a dedicated transmission line into the state. If the proper out-of-state transmission exists, these TRCs can count towards a supplier's RPS requirement, but will not count towards the aggregate capacity goals established in the legislation.³⁹

In 2003 Texas Governor Rick Perry appointed a 22-member Texas Energy Planning Council, which created Texas's first energy plan, "The Energy Contract with the People of Texas." This plan is not comprehensive, rather it is meant to be built on year after year. In October 2004, the council announced eight recommendations for the Texas Legislature to consider in 2005. Among these, was a recommendation to create a new law raising the percentage of electricity generated from renewable resources. The proposed law would raise the mandate to 5,000 megawatts of installed capacity by 2012

³⁴ Wiser, et al.

³⁵ Wiser et al.

³⁶ DSIRE

³⁷ Wiser et al.

³⁸ DSIRE

³⁹ Wiser et al.



and a goal of 10,000 megawatts by 2020, including required transmission lines. The law likely will depend on continued federal tax credits for wind power.⁴⁰

Table 1 below, estimates renewable energy sales for each state in 2010 and 2020 based on 2002 electricity sales and the renewable portfolio policies outlined above.

TABLE 1: RENEWABLE ENERGY MARKETS; ESTIMATED RENEWABLE ENERGY SALES IN 2010 AND 2020

State ⁴¹	2002 Electricity Sales (TWH)	Estimated 2010 Electricity Sales (TWH) ⁴²	2010 RPS Obligation ⁴³	Estimated Renewable Energy Market in 2010 Based on Current Mandates (TWH)	Estimated 2020 Electricity Sales (TWH) ⁴⁴	Projected 2020 RPS Obligation	Plausible Renewable Energy Market in 2020 Based on Projected Mandates (TWH) ⁴⁵
AZ	63	72	1.1%	0.80	87	5% ⁴⁶	4.4
CA	234	270	13%	35	323	33% ⁴⁷	106
CO	46	53	5%	2.65	63	10% ⁴⁸	6.4
NM	19	22	9%	2	26	10% ⁴⁹	2.6
NV	29	33	12%	4	40	15% ⁵⁰	6.0
TX	321	370	2.5%	9	440	9% ⁵¹	40

⁴⁰ "Texas' First Energy Plan is Moving Closer to Completion," Oct 26, 2004; San Antonio Express-News.

⁴¹ Department of Energy, Energy Information Administration Web site; Utility and ESP retail electricity sales in 2002 (http://www.eia.doe.gov/emeu/states/_states.html)

⁴² Estimated utility and ESP retail electricity sales in 2010 based on 2002 retail sales with a 1.8% compounded annual electricity sales growth rate.

⁴³ Wiser, Ryan; Kevin Porter, Robert Grace and Chase Kappel, "Evaluating State Renewables Portfolio Standards: A Focus on Geothermal Energy," National Geothermal Collaborative, 2003.

⁴⁴ Estimated utility and ESP retail electricity sales in 2020 based on 2002 retail sales with a 1.8% compounded annual electricity sales growth rate.

⁴⁵ CRS Projection.

⁴⁶ Projected RPS requirement in 2020 based on current discussions in Arizona.

⁴⁷ Projected RPS requirement in 2020 based on the California Governor's Remarks and the 2004 IEPR Update.

⁴⁸ Projected RPS requirement in 2020 based on Amendment 37, recently approved by ballot measure.

⁴⁹ Based on current RPS legislation, no enhancement.

⁵⁰ Based on current RPS legislation, no enhancement.

⁵¹ Based on recommendations of the Texas Energy Planning Council's The Energy Contract with the People of Texas.



SERVING SOUTHWEST STATE RENEWABLE ENERGY COMPLIANCE MARKETS WITH UNBLUNDED NEW MEXICO SOLAR RECS

While many energy officials across the west espouse the importance of regional approaches and cooperation regarding energy development, a strong sentiment also exists that encourages or, sometimes, requires that mandated renewable energy markets be served by indigenous renewable resources.

There is significant discussion in many western US energy circles (including the Western Governors Association) concerning the merits of creating a common renewable energy market throughout all of western North America (as currently exists for all other forms of electric power generation). Included in many of those forums is the potential of allowing unbundled renewable energy credits as a qualified RPS currency. At present, unbundled RECs, particularly those emanating from outside of each of the states that have renewable portfolio standards, are not considered to be an acceptable way to meet RPS obligations. Should there be shift in these regulations and policies, the prospect for using large scale New Mexico concentrating solar power to broadly serve western North American renewable energy compliance markets would expand significantly.

TABLE 2: NEW MEXICO SOLAR POWER AS AN RPS CURRENCY IN THE SOUTHWEST STATES

State	Contract Path Renewable Energy Delivery	Rebundled Energy and RECs	Stand Alone (unbundled) RECs
AZ	Yes	No	No
CA	Yes	No ⁵²	No ⁵³
CO	Yes	Yes ⁵⁴	Yes ⁵⁵
NM	Yes	No	No
NV	Yes	Yes ⁵⁶	No
TX	Yes	Yes ⁵⁷	No

⁵² See discussion in Section X that describes a November 11th meeting to consider unbundled RECs as a qualified California RPS currency.

⁵³ See discussion in Section X that describes a November 11th meeting to consider unbundled RECs as a qualified California RPS currency.

⁵⁴ The Colorado RPS takes effect on December 1st, but the PUC has until April 1 to start crafting rules to enforce it. The rule-making process, which must be finished by March 31, 2006, gives utilities time to meet the requirements for 2007.

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⁵⁶ Out-of-state generation is only eligible if there is a dedicated transmission line into the state. RECs must be issued by the Nevada PUC. Nevada's renewable energy producers can earn RECs, which can then be sold to utilities that are required to meet Nevada's portfolio standard.

⁵⁷ Out-of-state generation is only eligible if there is a dedicated transmission line into the state.



NEW MEXICO SOLAR POWER SALES INTO OTHER SOUTHWEST STATES:

In the southwest US, the largest markets are represented by the states of Texas and California. Colorado now also represents a potentially appreciable and important market. Each of these states has very aggressive renewable portfolio standards (see specific market summary of each state above).

There are many impediments associated with the sale of sizeable quantities of New Mexico Solar Renewable Energy Credits into each of those markets. While it may be difficult due to relative lack of available electric transmission from New Mexico into Texas and California, it may be plausible to consider direct solar electricity sales into each of those markets.

CALIFORNIA:

Market Access:

There is relatively robust transmission infrastructure between New Mexico and California. There are several high voltage transmission circuits between the Four Corners region of New Mexico, through Meade and Eldorado near Las Vegas, and into Adelanto, Victorville and Lugo near Los Angeles. These lines principally carry coal-based electric power between San Juan and Four Corners power plants to LA Basin load centers.

There is also some transmission line infrastructure between Luna in south western New Mexico, through the Palo Verde near Phoenix, and into Deavers near LA and Miguel near San Diego. The lines west of Phoenix principally carry nuclear and natural gas based electric power.

While each of these transmission corridors are plausible paths to deliver New Mexico solar power to California, the northern “coal” lines represent a more likely path. The oldest units at San Juan and Four Corners power plants are between 41 and 31 years old (see Appendix B for an overview of San Juan and Four Corners power plants). The oldest units have relatively poor environmental performance, are inefficient by today’s standards, and are near or beyond their originally planned service life.

Specific California utility ownership of northern New Mexico coal power includes:

Four Corners Unit 4; commissioned 1969; Southern California Edison share: 358 MW
San Juan Unit 3; commissioned 1979; SCCPA share: 204 MW
San Juan Unit 4; commissioned 1980; City of Anaheim share: 53 MW



In addition to the 615 MW of coal plant ownership by California utilities, additional coal power from these facilities is delivered to California energy markets annually based on contract or spot market purchases.

It may be of interest to all of the parties involved (coal plant owners and operators, transmission line owners, and California LSEs that import coal electricity from these facilities) to consider options and opportunities to reduce some of the coal electricity on these transmission corridors with replacement concentrating solar power. Such “contract path” delivery of renewable energy would be fully qualified renewable energy under current California RPS regulations.

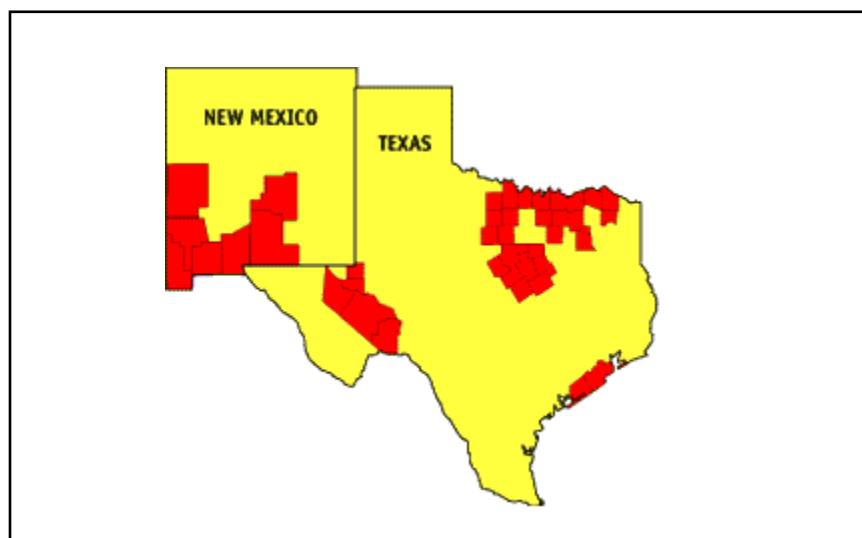
TEXAS:

Market Access:

Texas renewable energy markets are presently about 2.5 TWh/yr, and could grow to 40 TWh/yr over the next 15 years. Renewable energy power plants outside of Texas can serve Texas RPS obligations, but only through direct transmission deliveries into the state. Presently, extreme western portions of Texas have direct electric ties with the New Mexico grid. The greater El Paso area is directly interconnected with the WECC portion of the New Mexico grid and the extreme eastern portion of New Mexico is part of a common SPP grid with western and northern portions of the Texas panhandle (serving Lubbock and Amarillo load centers). The WECC portion of the New Mexico is interconnected to the SPP portion of New Mexico (and therefore the SPP portion of Texas). These points of interconnection are at the AC/DC/AC intertie at Blackwater and the AC/DC/AC Intertie at Artesia. There are several hundred MW of interchange capability at these substations. At present, there is limited interconnection between the WECC portion of New Mexico and ERCOT. However, the bulk of Texas’ load centers are located within ERCOT.

Two prominent electric utilities have service areas that include both New Mexico and Texas load centers – Texas New Mexico Power and El Paso Electric. It may be possible to build on the common markets served by these power companies to develop strategies that would allow New Mexico solar power to serve a portion of Texas’ RPS requirements.

Texas-New Mexico Power Company provides retail electric service to load centers in southwestern New Mexico, portions of Texas around Dallas and the Gulf Coast, and rural areas east of El Paso. Overall, the company currently serves more than 238,000 customers in 85 communities in Texas and New Mexico. TNMP's service territory is shown on the map below (TNMP service area shown in red or darkened areas).



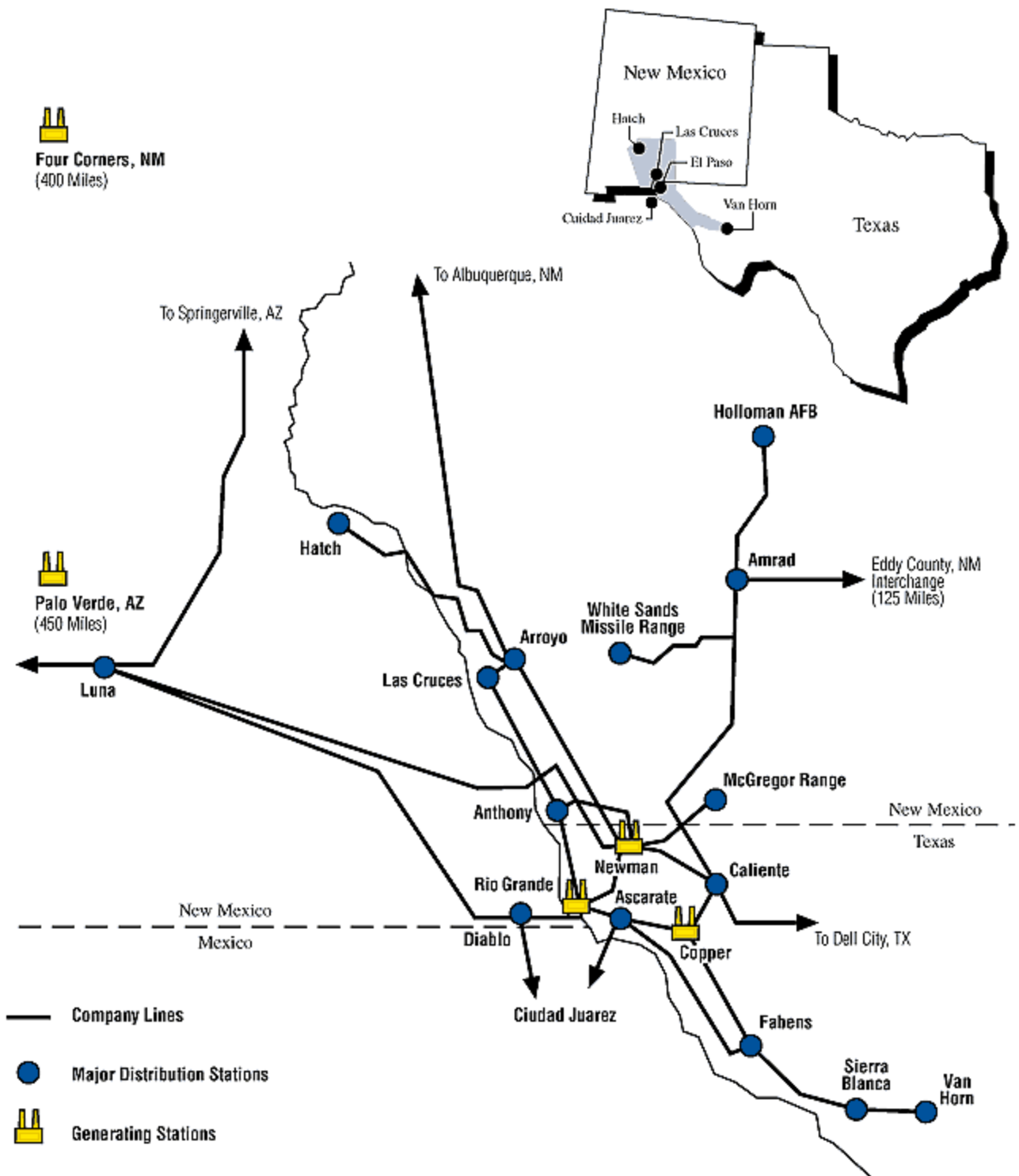
In New Mexico, TNMP operates as a fully integrated electric utility, handling transmission and distribution of power, along with power sales and service. TNMP does not own any generation in New Mexico but provides power through a long-term wholesale power contract with Public Service Company of New Mexico.

Since January 2002, TNMP has operated only as a transmission and distribution utility in Texas. The company previously had been a fully integrated utility but changed its focus as a result of the Texas Electric Choice Act, which brought electric competition to the state. The act required utilities to separate into both regulated and competitive companies. TNMP formed First Choice Power to be its competitive affiliate. First Choice Power provides electricity sales and service to customers in TNMP's service area and in other parts of the state as well.

Texas-New Mexico Power Company is a wholly owned subsidiary of TNP Enterprises, which previously traded on the New York Stock Exchange. In April 2000, the company completed an agreement to be acquired by a group of private investors. In July of 2004, TNP announced an intention to be acquired by Public Service of New Mexico.

El Paso Electric serves an area in Texas encompassing the El Paso metropolitan area and rural areas to the southeast of El Paso. It also serves south central New Mexico including Las Cruces. El Paso Electric serves approximately 300,000 customers and delivers approximately 15 million MWhrs/yr.⁵⁸

⁵⁸ See El Paso Electric Company Web site; <http://www.epelectric.com/>



Given the sheer size of the Texas electricity market, and the potential for a significant expansion of RPS targets for the state, a large scale CSP development strategy in New Mexico should consider options and opportunities to serve Texas markets. Texas renewable energy markets are presently served by large wind plants in west Texas and the Panhandle. These wind plants take advantage of economies of scale and good to excellent wind resources. As a result, electricity costs from these plants are quite



competitive (prices range from 3 to 5 cents/kWhr while taking advantage of production tax credits and other property and sales tax exemptions in some regions). There are approximately 1200 MW of wind power operating in the State, with the potential to increase by an order of magnitude or more.

While wind power provides a very attractive renewable energy resource for the state, over reliance on a single renewable energy technology may cause difficulties in the future with deliverability, supply of associated ancillary services, and a general match to load profile in the region. The State may begin to seek alternatives to wind to develop a more robust renewable energy portfolio. Specifically, Texas energy markets may find it desirable to begin to fold bulk solar power into its renewable energy mix as portfolio requirements expand over the coming decade. The solar resource is sufficiently superior in New Mexico (compared to Texas) that it may be beneficial for Texas to source bulk solar power from New Mexico.

Such an approach would represent a mid to long term energy strategy for the region. For instance, it may be useful to consider regional renewable energy exchanges. It may be attractive to bring low cost Texas wind energy into New Mexico, while shipping higher cost, higher value peak New Mexico solar energy and capacity into Texas. Opportunities to use CSP to shape or firm wind energy should be explored. Limited transmission between the two regions may make “energy swap” mechanisms between utilities or control areas an important approach.

COLORADO

Markets Access:

On November 2, Colorado passed a relatively aggressive renewable portfolio standard. Like Texas, Colorado has a vast wind resource, but a very limited solar resource. A major, regional wholesale power supply cooperative, Tri-State Generation and Transmission Association, has extensive distribution system membership in both Colorado and New Mexico. At present, Tri-State is not obligated under the New Mexico RPS (only investor owned utilities have a portfolio obligation). And Tri-State could become exempt from the Colorado RPS if their customer base so chooses. However, given the apparent strong desire of energy consumers through both Colorado and New Mexico to support renewable energy, Tri-State may choose to develop an aggressive renewable energy deployment approach for its customer base across the region.

Tri-State Generation and Transmission Association, Inc., is a nonprofit, wholesale power supply cooperative that provides electricity to 44 member distribution systems serving major parts of Colorado, Nebraska, New Mexico and Wyoming. The association also sells a portion of its generated power to other utilities in the region.⁵⁹

Tri-State was organized in 1952 by its member co-ops and public power districts and is owned by those systems. The G&T is guided by a board of directors comprised of

⁵⁹ See Tri-State Generation and Transmission Association Web site; <http://www.tristategt.org/>



representatives from each of the 44 member systems which, combined, provide electric service to approximately one million consumers. The association's primary function is to provide its member-owners a reliable, cost-based supply of electricity.⁶⁰

Tri-State owns and operates an extensive electric transmission grid that extends from southern New Mexico, north throughout Colorado and into Wyoming and Nebraska. This grid could plausibly be used for "contract path" solar power deliveries from New Mexico into those other states.⁶¹

As described above, there is a small solar power set aside within the Colorado RPS. The goal of this set aside may be to incentivise the development of distributed PV systems throughout Colorado load centers. To the extent the solar set aside is desired to create a wider portfolio of renewable energy resources, CSP technology could play an important role. Xcel estimates the solar requirements alone will cost \$355 million over the next 20 years.⁶² This estimate may be based solely on in-Colorado deployment of PV. However, using a mix of New Mexico (with highly superior direct normal insolation) CSP with in-Colorado PV could measurably lower the compliance cost of the Colorado RPS solar set aside.

SUMMARY - REGIONAL STRATEGY:

Three major electric power companies serve customer bases within a three state region where substantial renewable portfolio standards prevail.

Public Service of New Mexico, with its pending acquisition of Texas New Mexico Power, will serve a large customer base throughout New Mexico and Texas. El Paso Electric serves a significant portion of southern New Mexico as well as the El Paso metropolitan area in Texas. Tri-State Generation and Transmission serves a large customer base throughout New Mexico and Colorado. It may be beneficial for these power companies to examine aggregate approaches to serving these multi state RPS requirements. Several hundred MW of CSP power at a central New Mexico location may represent a cost effective, high value approach to developing a diversified set of renewable resources to serve the aggregate needs of the utilities serving the three state region.

Conclusions:

Although all of the southwest states have built in preferences for indigenous (to each of the states) renewable energy within their RPS statutes, it has also been recognized that there are many benefits associated with taking a regional, common-market approach to renewable energy supply.

⁶⁰ See Tri-State Generation and Transmission Association Web site; <http://www.tristategt.org/>

⁶¹ See Tri-State Generation and Transmission Association Web site; <http://www.tristategt.org/>

⁶² Change is in air for wind power," Gargi Chakrabarty, Rocky Mountain News November 3, 2004, http://www.rockymountainnews.com/drmn/election/article/0,1299.DRMN_36_3300453.00.html.



All of the southwest states represent potential market opportunities for New Mexico solar power. However, due to market size and market structure particulars, it appears that California, Texas and Colorado may represent the most attractive opportunities.

California has an excellent direct normal solar resource that is in close proximity to Los Angeles load centers. However, due to the significant transmission infrastructure connecting northern New Mexico to southern California, there may be cost effective opportunities to export New Mexico CSP to California markets. Opportunities to replace old, inefficient coal generation that lacks state-of-the-art emission controls, while significantly improving air quality in the Grand Canyon, Four Corners and San Jan Basin areas, may represent an important New Mexico CSP opportunity for California markets.

Colorado and Texas have vast wind resources but lack commercial quality direct normal solar radiation for bulk solar power production. As utilities in those states begin to fill out near term RPS obligations, they may find that over reliance on a single renewable energy resource (wind) that may lack significant capacity value, may not represent an optimal deployment approach. Three major utilities serve load centers throughout the Colorado-New Mexico-Texas region. These utilities should consider incorporating New Mexico CSP into a robust renewable energy portfolio that can serve PRS obligations across their multi state service territories.

State ⁶³	Renewable Energy Credit Eligibility	2010 RPS Obligation ⁶⁴	Estimated Renewable Energy Market in 2010 Based on Current Mandates (TWH)	Estimated 2020 Electricity Sales (TWH) ⁶⁵	Projected 2020 RPS Obligation	Plausible Renewable Energy Market in 2020 Based on Projected Mandates (TWH) ⁶⁶
CA	Not at present	13%	35	323	33% ⁶⁷	106
CO	Rebundled and unbundled RECs apparently allowed	5%	2.7	63	10% ⁶⁸	6.4
TX	Unbundled RECs allowed if electricity delivered to TX	2.5%	9	440	9% ⁶⁹	40

⁶³ Department of Energy, Energy Information Administration Web site; Utility and ESP retail electricity sales in 2002 (http://www.eia.doe.gov/emeu/states/_states.html)

⁶⁴ Wiser, Ryan; Kevin Porter, Robert Grace and Chase Kappel, "Evaluating State Renewables Portfolio Standards: A Focus on Geothermal Energy," National Geothermal Collaborative, 2003.

⁶⁵ Estimated utility and ESP retail electricity sales in 2020 based on 2002 retail sales with a 1.8% compounded annual electricity sales growth rate.

⁶⁶ CRS Projection.

⁶⁷ Projected RPS requirement in 2020 based on the California Governor's Remarks and the 2004 IEPR Update.

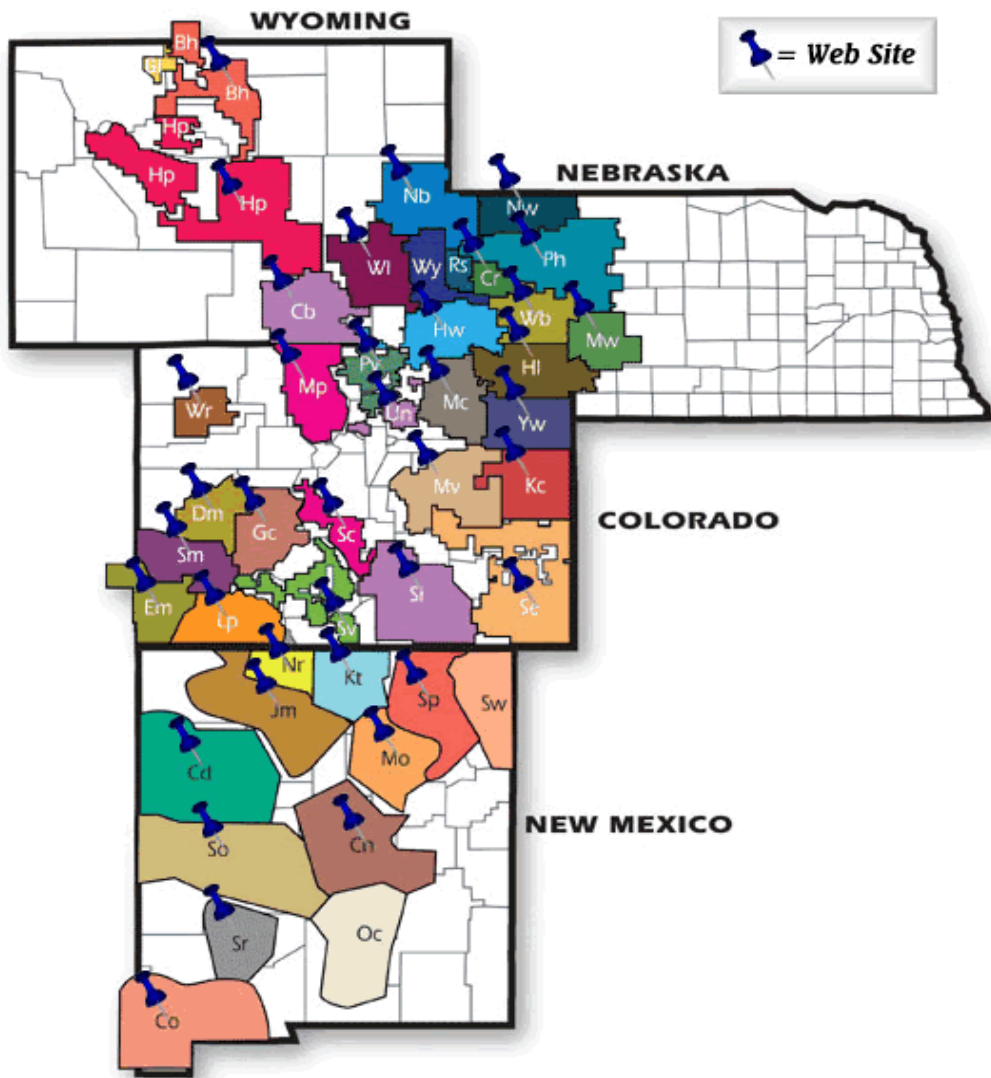
⁶⁸ Projected RPS requirement in 2020 based on Amendment 37, recently approved by ballot measure.

⁶⁹ Based on recommendations of the Texas Energy Planning Council's The Energy Contract with the People of Texas.



APPENDIX A

Tri-State G&T MEMBER DISTRIBUTION SYSTEMS





APPENDIX B

New Mexico Coal Plants Serving California Energy Markets

Four Corners Power Plant is one of the largest coal-fired generating stations in the United States. The plant is located on Navajo land in Fruitland, N.M., about 25 miles west of Farmington.

It was the first mine-mouth generation station to take advantage of the large deposits of sub-bituminous coal in the Four Corners region. The plant's five units generate 2,040 megawatts. The first unit went online in 1963. The plant, operated by Arizona Public Service Co., provides power to about 300,000 households in New Mexico, Arizona, California and Texas.

Four Corners Power Plant Ownership

Units 1, 2 and 3

- Arizona Public Service: 100 percent

Units 4 and 5

- Southern California Edison: 48 percent
- Arizona Public Service: 15 percent
- El Paso Electric: 7 percent
- PNM: 13 percent
- Salt River Project: 10 percent
- Tucson Electric Power: 7 percent

San Juan Generating Station, located about 15 miles northwest of Farmington, N.M., is operated by PNM and consists of four coal-fired, pressurized units that generate about 1,800 gross megawatts of electricity to serve PNM's customer base and that of eight other owners. It is the seventh-largest coal-fired generating station in the West. San Juan is PNM's primary generation source, serving 58 percent of the power needs of PNM customers.

Since it went online in 1973, San Juan has made a strong commitment to the environment by reducing air emissions and improving overall waste management and water management processes. These efforts have led to its charter membership in the EPA National Environmental Performance Track and its certification to ISO 14001 requirements.



The generating station has a large economic and community impact in San Juan County. It provides high-paying jobs and its employees are active in community organizations that support the excellent quality of life in the area.

With the station's four units ranging in age from 23 to 31 years, its owners need to make decisions regarding future operations and to begin considering possible plant retirement scenarios. EPRI and Public Service Company of New Mexico have undertaken a detailed life study that will enable the integration of a diverse set of perspectives, ranging from plant equipment condition evaluation and reliability/cost prognosis to an assessment of regulatory and market risks, trends, and uncertainties. This report discusses the first phase of the study, which established a baseline evaluation, defined important externalities, and laid the groundwork for the remaining phases. With the information provided by the study, the owners will be able to evaluate likely scenarios of regulatory and market risks and opportunities, make decisions regarding critical plant equipment, and define options for future plant investments or retirements.

San Juan Generating Station Ownership

Units 1 and 2

- PNM: 50 percent
- Tucson Electric Power: 50 percent

Unit 3

- PNM: 50 percent
- Southern California Public Power Authority: 41.8 percent
- Tri-State Generation and Transmission Association: 8.2 percent

Unit 4

- PNM: 38.5 percent
- MSR Public Power Agency: 28.8 percent
- City of Anaheim, Calif.: 10 percent
- City of Farmington: 8.5 percent
- Los Alamos County: 7.2 percent
- Utah Associated Municipal Power Systems: 7 percent

Each year, Four Corners emits about 45,000 tons of nitrogen oxide, San Juan about 25,000 tons.

Annually, Four Corners emits about 35,000 tons of SO₂, San Juan about 15,000 tons. Every year the San Juan power plant and the nearby Four Corners power plant emit more than 136,000 tons of sulfur dioxide and nitrogen oxides combined (2001 EPA data).